Increasing Heavy Oil Reserves in The Wilmington Oil Field Through Advanced Reservoir Characterization And Thermal Production Technologies

Annual Report for the Period
April 1, 1996 to March 31, 1997

Prepared for
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June 1999

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ABSTRACT

The objective of this project is to increase the recoverable heavy oil reserves within sections of the Wilmington Oil Field, near Long Beach, California. This is realized through the testing and application of advanced reservoir characterization and thermal production technologies. It is hoped that the successful application of these technologies will result in their implementation throughout the Wilmington Field and, through technology transfer, will be extended to increase the recoverable oil reserves in other slope and basin clastic (SBC) reservoirs.

The existing steamflood in the Tar zone of Fault Block (FB) II-A has been relatively inefficient because of several producability problems which are common in SBC reservoirs: inadequate characterization of the heterogeneous turbidite sands, high permeability thief zones, low gravity oil and non-uniform distribution of the remaining oil. This has resulted in poor sweep efficiency, high steam-oil ratios, and early steam breakthrough. Operational problems related to steam breakthrough, high reservoir pressure, and unconsolidated sands have caused premature well and downhole equipment failures. In aggregate, these reservoir and operational constraints have resulted in increased operating costs and decreased recoverable reserves.

A suite of advanced reservoir characterization and thermal production technologies are being applied during the project to improve oil recovery and reduce operating costs, including:

1. Development of three-dimensional (3-D) deterministic and stochastic reservoir simulation models - thermal or otherwise - to aid in reservoir management and subsequent development work.

2. Development of computerized three-dimensional (3-D) visualizations of the geologic and reservoir simulation models to aid reservoir surveillance and operations.

3. Perform Detailed study of the geochemical interactions between the steam and the formation rock and fluids.

4. Testing and proposed application of a novel alkaline-steam well completion technique for the containment of the unconsolidated formation sands and control of fluid entry and injection profiles.

5. Installation of a 2100 ft, 14" insulated, steam line beneath a harbor channel to supply steam to an island location.

6. Testing and proposed application of thermal recovery technologies to increase oil production and reserves:

    a) Performing pilot tests of cyclic steam injection and production on new horizontal wells.

    b) Performing pilot tests of hot water-alternating-steam (WAS) drive in the existing steam drive area to improve thermal efficiency.

7. Perform a pilot steamflood with the four horizontal injectors and producers using a pseudo steam-assisted gravity-drainage (SAGD) process.

8. Advanced reservoir management, through computer-aided access to production and geologic data to integrate reservoir characterization, engineering, monitoring and evaluation.

Key accomplishments for this reporting period include:

1. Development of a petrophysical rock-log model

2. Completion of a basic reservoir engineering study of Fault Block II-A, Tar Zone.

3. Initiated the building of a 3-D Thermal reservoir simulator.

4. Commencement of cyclic steam injection into four horizontal wells (two injectors, two producers) following the successful installation of the 2100ft steam line.

5. Initiation of continuous steam injection into the two horizontal injection wells.

6. Conversion of four hot water-alternating-steam pilot injectors and four steam injectors to hot water injection.

7. Generation of particular interest among other operators within industry in two technologies developed as a result of the project, namely:
    a) 3-D geologic modeling work, and
    b) a novel low-cost well completion technique using steam for formations with unconsolidated sands.

8. The design and application of an improved caustic H_2S stripper.

9. Design and installation of a 7ppm NO_x 50MMBtu/hr Oilfield Steam Generator operating on low-Btu produced gas.

10. Participating in numerous technology transfer activities.

EXECUTIVE SUMMARY

Introduction

The objective of this project is to increase the recoverable heavy oil reserves within sections of the Wilmington Oil Field, near Long Beach, California. This is realized through the testing and application of advanced reservoir characterization and thermal production technologies. It is hoped that the successful application of these technologies will result in their implementation throughout the Wilmington Field and, through technology transfer, will be extended to increase the recoverable oil reserves in other slope and basin clastic (SBC) reservoirs.

The project involves the implementation of thermal recovery in the Tar zone of Fault Block (FB) ll-A. The existing steamflood has been relatively inefficient due to several producability problems commonly associated with SBC reservoirs. Inadequate characterization of the heterogeneous turbidite sands, high permeability thief zones, low gravity oil, and non-uniform distribution of the remaining oil have all contributed to poor sweep efficiency, high steam-oil ratios and early steam breakthrough. Operational problems related to steam breakthrough, high reservoir pressure, and unconsolidated formation sands have caused premature well and downhole equipment failures. In aggregate, these reservoir and operational constraints have resulted in increased operating costs and decreased recoverable reserves.

The first phase of the project - initiated during the previous year as detailed in the annual report ending March 31, 1996 - begins with applying advanced reservoir characterization methods to enable improved design and application of thermal recovery methods. A petrophysical rock-log model was completed by the 1st quarter of this work year. A deterministic geologic model of the reservoir has been completed and a stochastic model is being created. The geologic models will be used in reservoir simulators to optimize reservoir management and thermal recovery methods. A deterministic reservoir simulation of the primary production phase has been completed and history matching of the waterflood phase is underway. Through technology transfer activities, our research into three-dimensional (3-D) modeling activities have generated widespread interest within the petroleum community.

At the end of the reporting period, cyclic steam injection was performed on four horizontal wells of which two have been converted to continuous steam injection. Four additional vertical steam injectors have been converted to hot waterflooding for a total of eight vertical water-alternating steam (WAS) injectors. The above mentioned activities have been carried out as three pilot tests to comparatively evaluate different viable methods of thermal recovery. The 2100-ft steam line has been in trouble-free operation following start-up in December 1995 as detailed in the annual report ending 31 March 1996. To date, the line has been supplying steam to the four horizontal wells. No new drilling operations have been initiated during the work year. The current tally for drilling operations, following the commencement of the project, stands at two horizontal producers, two horizontal injectors and five observation wells. The horizontal wells were completed using the novel alkaline-steam injection treatment, which has been quite successful at reducing sanding problems and decreasing completion costs. This has generated widespread interest within the petroleum community through technology transfer activities. The quality of injected steam and hot water is being controlled using a new steam/hot water separator. Also, high temperature core work and the reservoir tracer program were initiated in the closing quarter of the reporting period.

In the second budget period, a series of horizontal wells will be drilled to extend the thermal recovery project to the remainder of the D1 sands in the Fault Block II-A Tar zone, based on the results of the simulation studies and pilot tests. It is anticipated that four horizontal producers, four horizontal injectors and three observation wells will be drilled.

The overall project is expected to take over seven years to complete. The first budget period began in March 1995 and is expected to end during the first quarter of 1999. The second phase is expected to take place from 1999 through 2002.

The project is being implemented by a team including:

1. The City of Long Beach - the operator of the field as a trustee of the State of California-granted tidelands;

2. Tidelands Oil Production Company - the contract operator of the field for the City of Long Beach, and the party in-charge of implementing the project;

3. The University of Southern California, Petroleum Engineering Program - consultants to the project, playing a key role in reservoir characterization and simulation; and

4. David K. Davies and Associates - consultants to the project regarding petrography, rock-based log modeling, and geochemistry of rock and fluid interactions.

Expanding thermal recovery operations to other sections of the Wilmington Oil Field is a critical part of the City of Long Beach and Tidelands Oil Production Company's development strategy for the field. The current thermal operations in the Wilmington Field are economical with today's oil prices due to the availability of inexpensive steam from an existing cogeneration plant and from a 50 MMBTU/hr steam generator that can utilize non-commercial low Btu produced gas. Such favorable terms for obtaining steam are not expected to be available in the future. Future expansion of thermal recovery to other parts of the Wilmington Field will depend on improving the efficiency and economics of heavy oil recovery, as is the intent of the project.

Advanced Reservoir Characterization

Basic Reservoir Engineering

At the start of the reporting period, the project centered around basic reservoir engineering work. Work was performed on evaluating the role of aquifer water influx and determining the original oil in place from gas production data to support the material balance work. Work completed includes;

1. An analysis on the primary and waterflood recoveries, permeability estimates from performance data.

2. Comparing water injection profile surveys to the allocated injection volumes for each sub-zone.

3. Determining the quality of the new and old well logs.

4. Determining the vertical communication between sands.

5. Evaluating the aquifer and solution gas.

6. Performing correlation studies on projected steam recoveries from vertical and horizontal wells.

Three Dimensional Modeling

A three-dimensional (3-D) deterministic geologic model was completed and a stochastic geologic model is being created to describe the heterogeneous turbidite geology of the Fault Block II-A Tar zone. Determining sand continuity is of particular importance for turbidite sands, because sand sequences in adjacent wells may look similar but in fact may not be connected because of the lobated nature of the sand sequences.

Data for the geologic models are being derived from existing logs from over 600 wells, detailed core studies, Measurement While Drilling (MWD) and Logging While Drilling (LWD) data from the installation of four new horizontal wells, open hole logs from five new observation wells and a tracer study. To facilitate future reservoir analysis and interpretation, geologic models were constructed using the EarthVision™ 3-D imaging software by Dynamic Graphics, Inc. These processes collectively identified the existence of a north-south gradient of sand quality, the presence of a major channel sand cutting through the upper "T" sands, and the existence of previously unmapped faults.

A 3-D deterministic geologic model was completed which is being used to develop the 3-D stochastic model in addition to being used for drilling the observation and horizontal wells. The deterministic model correlates eighteen horizons in the Tar zone. Existing cores were inspected before determining their suitability for the derivation of a core-based log model, a porosity-permeability model and a rock-log model.

Rock-Log Model

During the first quarter, a petrophysical rock-log model was completed. Building the model required three tasks: to distinguish between the five petrophysical rock types identified in the T and D sand intervals; the development of an empirical porosity-permeability relation for each rock type; and to correlate specific induction, gamma ray and spontaneous potential log characteristics with core data of each rock type. The purpose of the model is to predict petrophysical rock types and permeability profiles for T and D sands in locations where only minimum log data and no core data are available. The model has been applied to uncored wells within the area to aid in reservoir description and permeability modeling for the stochastic and reservoir simulation models.

Published Work

By the third quarter, several draft reports have been produced outlining the basic reservoir engineering work. The reports are entitled "Application of Basic Reservoir Engineering Techniques to the Tar Zone, Fault Block II-A, Wilmington, CA", "Study of Pre-1960 Well Logs in Fault Block II-A, Wilmington Field", and "Study of Water Injection Surveys, Tar Zone Fault Block II, Wilmington Field".

Draft reports related to reservoir characterization which have been completed include; "Stratigraphic Equivalents of the Wilmington Field, 'Tar Zone' in the subsurface Los Angeles Basin, California", and "Barrier Characteristics of the Geologic Faults"

Sand Sequence Analysis

A sand sequence analysis of the geologic column in the Tar zone is being conducted to map local effects requiring special correlation studies during the conceptual modeling phase. Also, the existing neural network analyzer has been continuously upgraded to analyze the similarities of various zones and sub-zones in terms of sequence stratigraphy using gamma ray, spontaneous potential, density, neutron and resistivity logs, and to improve signal compression through linear transform techniques.

Study on Steam Drive Recovery

A parametric study on the projected steam drive recoveries from vertical and horizontal wells was initiated in the third quarter of the work year. The study utilized the TETRAD™ thermal reservoir simulator program, a product of Dyad 88 Software Inc. The aim of the study is to compare recovery from both types of well completions as a function of reservoir properties, crude oil characteristics, and injection strategies. The study is still under way at the end of the work year.

Reservoir Tracer Program

The reservoir tracer program was initiated in the last quarter of the work year with the bulk injection of ammonium thiocyanate (AT) and lithium chloride (LC) tracers on February 14 1997 into two hot water-alternating-steam pilot injectors. Sampling of produced fluids from first and second rows of producers are being collected for analysis of the ammonium and lithium tracers.

High Temperature Core Work

High temperature core work was also initiated in the last quarter of the work year, with the intent of measuring formation rock compaction and expansion due to steamflooding. This is in addition to the original proposal to carry out core work for steam pot tests and measurement of geochemical effects of high temperature steam on the reservoir rocks and fluids. This task is expected to commence during the following quarter. The purpose of the additional core work is for future use in the calibration of the thermal reservoir simulation model.

Reservoir Simulation

After benchmark tests conducted by the project team and Computer Modelling Group (CMG) of Calgary, the STARS™ thermal reservoir simulation software by the CMG was installed on a R10,000 Onyx RE2 work station by Silicon Graphics Incorporated (SGI) for modeling purposes. By the third quarter, history matches covering the primary depletion period had been completed using both the CMG IMEX™ black oil simulator program and STARS™.

The project team identified two dynamic reservoir processes, which significantly affect the history matches; compaction-related deformation of the rock and gas liberation. The project team has developed a rock compaction algorithm, which is able to mimic the local and dynamic features of rock compaction and rebound as a function of reservoir pressure. CMG incorporated this algorithm into an alpha version of STARS 97.00, entitled STARS 97.20 for testing purposes. If successful, the algorithm will be incorporated into a full working version entitled STARS 98.00 in January 1998.

During the preliminary runs, the single component oil (dead oil) feature of STARS has been applied in simulations to speed up the modeling work of the primary and waterflood production phases. The simulation appears to exhibit stability.

Reservoir Management

The key reservoir management activities during the first budget period include implementing three pilot tests of thermal recovery:

1. Cyclic steam stimulation through horizontal wells;
2. Steam drive through horizontal wells; and
3. Hot water-alternating-steam (WAS) drive in mature vertical well steamflood patterns.

Other indirectly associated reservoir activities of note are:

4. Design and installation of an improved caustic H_2S scrubber system.
5. Installation of a 7ppm NO_x 50MMBtu/hr oil field steam generator operating on low Btu waste gas.

In mid-December 1995, the 2100-ft steam transmission line under the Cerritos Channel was placed in service. No problems have been experienced to date.

The first budget period involves the drilling, completion and operation of four horizontal wells drilled in late 1995 into the target D1 sands. The wells (two steam injectors and two producers) were completed over the last 600-ft of the 1500-1800-ft horizontal lateral sections.

Cyclic steam stimulation was initiated in injection wells 2AT-61 and 2AT-63 during the first half of 1996 and production commenced in early summer. Gross production ranged from 1200-1500 BPD/well compared to projected production rates of 1500 BPD/well. Injector wells 2AT-61 and 2AT-63 were converted to continuous injection in November 1996 and January 1997, respectively. Production wells UP-955 and UP-956 underwent cyclic steam stimulation during the second half of 1996. UP-955 achieved cyclic peak production rates of 1450 BPD gross and 80 BPD oil, while UP-956 achieved cyclic peak production rates of 1570 BPD gross and 103 BPD oil. Each well was given a one-month steam soak period prior to initiating production. These rates were lower than the projected rates of 2100 BPD gross and 300 BPD oil. At the close of the work year, UP-956 reported a gradual increase in gross and oil production rates, however, UP-955 oil production experienced a decrease in oil production and an increase in gross production. Hopefully, UP-955 will exhibit a favorable response to steam drive injection from the two offset horizontal injectors.

Four existing steam injection wells were converted to hot water injection from March 1995 to February 1996. No positive or negative production response was observed. Hot water injection was discontinued from February to November 1996 to move the hot water separator facility to satisfy surface landowner requirements and steam injection was resumed. Hot water injection was restarted in November 1996 and expanded to eight injection wells.

An improved H_2S caustic scrubber was designed and implemented by a joint team of engineers from T.J. Cross Engineers and Tidelands Oil Production Company, adapting the H_2S caustic scrubber principle proposed by Dow Chemical (Patent No. 2,747, 962). The scrubber would be utilized for stripping H_2S from steamflood related produced gas streams at less than half the previous cost.

The new scrubber process (entitled Lo~CoST[SM]) improves the caustic mixing system by gas contact by way of an ejector-venturi contactor, followed by gas separation. The added efficiency allows for a lower caustic concentration. A more effective caustic substitute called SulfaTreat[TM] removes lower H_2S concentrations in the latter of a two-stage process.

A 7ppm NO_x 50MMBtu/hr oil field steam generator utilizing the non-commercial low Btu produced gas from Tidelands Operations was installed in the Fault Block V area. The lowest uqality gas is produced from the Fault Block II-A, Tar zone. A pilot steamflood was initiated in the Fault Block V, Tar zone in 1996 based on drilling and operating lessons learned in this project and by turning a negative situation (waste gas) into a growth opportunity. The unit was the first 50MMbtu/hr-steam generator permitted in the Los Angeles Basin since the 1980s. The steam generator, by Stuthers, was delivered in February 1996 and system check out started in June 1996. The burner was designed and built by North American Manufacturing Company and guaranteed to emit under 9ppm NO_x without selective catalytic reduction (SCR). NO_x control was dictated by maintaining the air-fuel mix at lean condition. The SCAQMD (South Coast Air Quality Management District) requires that stack emissions data be sent to the SCAQMD via a modem using a Continuous Emissions Monitoring System (CEMS). Stack emissions were in compliance with the SCAQMD guidelines, with stack emissions tested at 5.44ppm without FGR (Flue Gas Recirculation) and a burner not equipped with SCR. This was verified by a third party stack testing laboratory, World Environmental.

A novel well completion technique tailored towards stabilizing unconsolidated, porous and permeable sands has been successfully applied in the Tar Zone of the Wilmington Field. The technique, which involves the application of steam, has been used successfully in 13 vertical and 9 horizontal wells through mid-1997 in place of more expensive gravel-packed slotted liner completions. Sand control was achieved without any adverse effects on well productivity. The successful application of this technique has resulted in significantly lower drilling and completion costs, better control of fluid profiles into the well-bore, interchangeability of production and injection wells as they now share common drilling and completion methods, and more workover flexibility.

Operational Management

Implementing thermal recovery in the Fault Block II-A Tar zone poses a variety of operational problems. Past thermal operations in the Wilmington Field have experienced premature well and downhole equipment failure due to early steam breakthrough and sanding problems, as is commonly associated with other SBC reservoirs with heterogeneous geology and unconsolidated sands. In addition, the high reservoir pressure and associated high steam temperature in the Wilmington Field aggravate the wellbore and equipment problems associated with early steam breakthrough. A variety of approaches are being investigated to alleviate operational problems, thereby increasing the effectiveness and reducing the costs of thermal recovery operations.

The alkaline hot water/steam well completion technique for sand consolidation is believed to cause minor sand grain dissolution and precipitation. This results in consolidation of the formation sand grains and controlling sand movement into the wellbore. Experience with existing horizontal wells in Fault Block I Tar Zone suggests that, if the perforations are too numerous or too large, then much higher steam rates and volumes are required to consolidate the sand. This completion technique was used in the four horizontal wells. To date, no sand inflow has occurred in any of the wells.

Geochemical studies are being performed to better understand the mechanisms responsible for carbonate scale formation in producing wells, which has been a significant problem in the past.

Thin section, scanning electron microscope, and x-ray diffraction studies performed to date on fill samples from existing steamflood producers have identified the types of scale produced as calcite, dolomite, barite, anhydrite, and magnesium-silicated minerals.

At present, high temperature core work is being performed to measure rock compaction due to steamflooding, geochemical effects of high temperature steam on the reservoir rocks and fluids (to commence the following work year), and steam pot tests. In addition to finding the mechanisms for carbonate scale formation, the high temperature core work also provides permeability data necessary for thermal reservoir simulation models.

Expansion Program

The thermal project will be expanded to the remainder of the undeveloped D1 sand in the Fault Block II-A Tar Zone in Budget Period 2 of the project, based on the results of reservoir characterization, reservoir simulation and pilot testing in Budget Period 1. The expansion is scheduled to start in the second quarter of 1999 and proceed to 2002. It is anticipated that four horizontal producers, four horizontal injectors and three observation wells will be installed during the second budget period.

The expansion has a drainage area of approximately 83 acres and a net oil sand thickness of 75 ft. The remaining oil saturation after waterflooding is estimated to be 66%. The remaining oil in place is estimated to be 9,625,000 barrels of oil. Projected recovery from the expansion is estimated to be 5,100,000 barrels of oil. The total pilot and expansion projected cumulative oil production is estimated to be 7,117,000 barrels.

Technology Transfer

Presentations

Four poster sessions and a field tour were presented at the 1996 Annual American Association of Petroleum Geologists (AAPG) Convention in May in San Diego. Also, four presentations have been scheduled for the project team at both the upcoming AAPG Annual Meeting in Dallas, TX, on April 7-9, 1997 as well as the AAPG Pacific Section Convention in Bakersfield, in May 14-16, 1997.

The project team has made presentations on the major activities completed and the status of the project to representatives from the DOE Bartlesville Project Office on September 19, 1996 in Tideland's office in Long Beach.

The project team was heavily involved in Petroleum Technology Transfer Council (PTTC) activities. Presentations were made at the PTTC problem identification workshop, held in Bakersfield, Long Beach and Ventura on the 20th, 25th and 26th of November 1996. The Opening ceremony of the West Coast PTTC office - located at the University of Southern California - served as an opportunity to showcase work associated with the project. The inaugural workshop was held on January 15 1997 entitled "California Geology - With or Without Computer Graphics". A ½ day workshop was scheduled for the 2nd of May entitled "Three-Dimensional Geologic Modeling", which will feature the Wilmington Field 3-D geologic model. The DOE Class III projects have been highlighted in the workshops. The technical transfer commitment for this and other DOE projects has led to the establishment of a Regional Lead Organization office of the Petroleum Technology Transfer Council (PTTC) at the University of Southern California.

Other presentations made by the project team were at various SPE conferences and monthly meetings, the 8th Annual Energy Week Conference in Houston, TX (30th January 1997) and the 4th International Reservoir Characterization Technical Conference (2-4 March 1997) in Houston.

Published Work

A magazine article was published in the September 1996 Issue of the American Oil and Gas Reporter entitled “3-D Modeling, Horizontal Drilling... Give New Life to Aging Fields” by Chris Phillips, Don Clarke, and Linji An. An article entitled “Coaxing Crude from the Ground” was published in Compressed Air Magazine. The article included an interview with project member, Dr. Iraj Ershaghi on detailed field characterization.

Within the last quarter of the work year, three articles were published in the Los Angeles Times concerning the oil industry in the Los Angeles Basin. These articles featured significant technical input from the project team members. Four meetings were requested by operators to present specific project-related technologies.

A two-volume book on the geology and operation of slope and basin clastic oil and gas reservoirs is being organized. The first volume on SBC geology is anticipated to be completed in 1999. Work on a second volume on operations has not started yet.

In addition, there have been a number of papers published or awaiting publication that have been written by the project team members during the first project year. Almost all of these papers have been presented at various conferences and meetings, as detailed in the First Annual Report.

Society of Petroleum Engineers, 1997 Western Regional Meeting

The project team is conducting an innovative program to make available the technical advances from the project. Project activities planned at the WRM includes one field trip, 6 papers, and 3 oral presentations. Several project team members are significantly involved in the planning of the upcoming 1997 Society of Petroleum Engineers Western Regional Meeting (WRM) scheduled for June 23-27, 1997 in Long Beach. The WRM is being structured to provide a more practical and timely approach, with regard to presentations, to meet the needs of a broader industry audience.

Web site/CD-ROM project

A new home page was created for the project on the Internet (http: //www.usc.edu/peteng/topko.html). A CD-ROM of the project has been completed for content and will be distributed at the 1997 SPE Western Regional Meeting. The CD-ROM can be accessed by Microsoft Windows95 operating systems.

Commercial Development

In the process of creating the deterministic reservoir model, the project team had created an algorithm, which is capable of taking into account the local and dynamic features of rock compaction and rebound with respect to reservoir pressure. This algorithm is to be included in the Computer Modelling Group (CMG) STARS™ 98.00 version.

The Lo-Cost^{SM} process developed by the project team is a two-stage process, which is capable of reducing the H_2S concentration to < 4 ppm by Sulfatreat^{TM}. The net cost of removal of a pound of Sulfur is \$0.43, which translates into a yearly operating cost of \$226,000. This is significantly lower than the original four-stage process, which cost \$0.74 per pound of Sulfur and a yearly operating cost of \$393,000.

Future Involvement

The project team has committed to 32 activities during the following six months. The technology transfer effort has been facilitated largely, but not limited to, the team's key involvement in the West Coast PTTC organization, the 1997 AAPG National and Pacific Section Meetings, and the 1997 SPE Western Regional Meeting. Two papers have been accepted for the 1997 SPE Annual Technical Conference in San Antonio, TX (5-8 October 1997). Most of the papers and presentations to be given are about technical work that was completed by March 1997 and are referenced and included in this Annual Report.

ACKNOWLEDGMENTS

This research is performed under the Class III Oil Program of the U.S. Department of Energy (DOE), Pittsburgh Energy Technology Center, contract number DE-FC22-95BC14939. The Contracting Officer's Representative is Jerry Castille, with the DOE National Petroleum Technology Offices in Tulsa, OK.

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1 INTRODUCTION

1.1 Report Overview

This is the second annual technical progress report for the project. Although the contract was awarded on March 30, 1995 and Pre-Award Approval was given on January 26, 1995, work was initiated on October 1, 1994. The first report submitted covered the period from initiation to March 31, 1996. The current report covers the period from April 1, 1996 to March 31, 1997.

The remainder of the chapter provides an overview of the project and the Wilmington Oil Field, in which the project is being implemented. Subsequent chapters summarize the objectives, status and conclusions to date of the major activities of the project. The report concludes by describing technology transfer activities stemming from the project and providing a list of related references.

1.2 Project Overview

The objective of this project is to increase the recoverable heavy oil reserves within sections of the Wilmington Oil Field, near Long Beach, California. This is brought about by the testing and eventual application of advanced reservoir characterization and thermal production technologies. It is hoped that the successful application of these technologies will result in their implementation throughout the Wilmington Field and, through technology transfer, will be extended to increase the recoverable oil reserves in other slope and basin clastic (SBC) reservoirs.

The project involves the implementation of thermal recovery in the Tar zone of Fault Block (FB) II-A. The existing steamflood has been relatively inefficient due to several producability problems commonly associated with SBC reservoirs. Inadequate characterization of the heterogeneous turbidite sands, high permeability thief zones, low gravity oil, and non-uniform distribution of the remaining oil have all contributed to poor sweep efficiency, high steam-oil ratios and early steam breakthrough. Operational problems related to steam breakthrough, high reservoir pressure, and unconsolidated formation sands have caused premature well and downhole equipment failures. In aggregate, these reservoir and operational constraints have resulted in increased operating costs and decreased recoverable reserves.

A suite of advanced reservoir characterization and thermal production technologies are being applied during the project to improve oil recovery and reduce operating costs, including:

1. Development of three-dimensional (3-D) deterministic and stochastic reservoir simulation models - thermal or otherwise - to aid in reservoir management and subsequent development work.

2. Development of computerized three-dimensional (3-D) visualizations of the geologic and reservoir simulation models to aid analysis.

3. Perform detailed study on the geochemical interactions between the steam, formation rock and associated fluids.

4. Testing and proposed application of a novel alkaline-steam well completion technique for containment of formation sand and control of fluid entry profiles.

5. Installation of a 2100-ft, 14" insulated steam line, underneath a harbor channel to an island location.

6. Testing and proposed application of thermal recovery technologies to increase oil production and reserves:

   a) Performing pilot tests of cyclic steam injection and production on new horizontal wells.
   b) Performing pilot tests of hot water-alternating-steam (WAS) injection in the existing steam drive area to improve thermal efficiency.

7. Perform a pilot steamflood with the four horizontal injectors and producers using a pseudo steam-assisted gravity-drainage process.

8. Advanced reservoir management through computer-aided access to production and geologic data to integrate reservoir characterization, engineering, monitoring and evaluation.

Key accomplishments for this reporting period include:

1. Development of a petrophysical rock-log model. [A21-22, C6, C32]

2. Completion of a basic reservoir engineering study of Fault Block II-A, Tar Zone. [A14, C10]

3. Initiated the building of a 3-D deterministic thermal reservoir simulator. [A25, C9]

4. Commencement of cyclic steam injection into four horizontal wells (two injectors, two producers) following the successful installation of the 2100ft steam line. [A9]

5. Initiation of continuous steam injection into the two horizontal injection wells.

6. Conversion of four hot water-alternating-steam pilot injectors and four steam injectors to hot water injection.

7. Generation of particular interest among other operators within industry in two technologies developed as a result of the project, namely:
   a) 3-D geologic modeling work, and [A6-8,A10-13,B7,C1,C11, C14-17,C20,C25]
   b) a novel low-cost well completion technique using steam for formations with unconsolidated sands. [A19, C4, C24]

8. The design and application of an improved caustic H_2S stripper. [A18,B5,C18]

9. Design and installation of a 7ppm NO_x 50MMBtu/hr Oilfield Steam Generator operating on low-Btu produced gas. [A16]

10. Participating in numerous technology transfer activities. [B8-9,C2-3,C7-8,C12-13,C23,C26]

The project is being conducted in two budget periods. The first budget period - initiated during the previous year as detailed in the annual report ending March 31, 1996 - begins with applying advanced reservoir characterization methods to enable improved design and application of thermal recovery methods. A petrophysical rock-log model was completed by the 1st quarter of this work year. A deterministic geologic model of the reservoir has been completed and a stochastic model is being created. The geologic models will be used in reservoir simulators to optimize reservoir management and thermal recovery methods. Through technology transfer activities, our research into three-dimensional (3-D) activities have generated widespread interest within the petroleum community.

By the end of the reporting period, the four new horizontal wells were given cyclic steam stimulation jobs and continuous steam injection was being implemented on two horizontal wells. Four additional steam injectors were converted to hot waterflooding in line with the water-alternating steam (WAS) drive tests. The above mentioned activities have been carried out as three pilot tests to comparatively evaluate different viable methods of thermal recovery. The 2100-ft steam line has been in full operation following start-up operation as detailed in the annual report for the year ending March 31, 1996. Currently, the line is supplying steam to the two horizontal injection wells. No new drilling operations have been initiated during the work year. The current tally for drilling operations, following the commencement of the project, stands at two horizontal producers, two horizontal injectors and five observation wells.

The horizontal wells were completed using the novel alkaline-steam injection treatment, which has been quite successful at reducing sanding problems and decreasing completion costs. This has generated widespread interest within the petroleum community through technology transfer activities. The quality of injected steam is being controlled using a steam/hot water separator to provide operating flexibility to optimize recovery efficiency. Also, high temperature core work and the reservoir tracer program were initiated in the closing quarter of the work year.

In the second budget period, a series of horizontal wells will be drilled to extend the thermal recovery project to the remainder of the D1 sands in the Fault Block II-A Tar zone, based on the results of the simulation studies and pilot tests. It is anticipated that four horizontal producers, four horizontal injectors and three observation wells will be drilled.

The overall project is expected to take over seven years to complete. The first budget period began in March 1995 and is expected to end during the first quarter of 1999. The second phase is expected to take place from 1999 through 2002.

The project is being implemented in terms of a series of activities and associated tasks. The activities and the chapters in which they are being discussed are listed below:

Chapter	Activity	Description
2	1	Compilation and Analysis of Existing Data - Compilation and evaluation of production, injection, PVT and log data for simulation models.
3	2	Advanced Reservoir Characterization - Analysis of existing and new reservoir data to develop deterministic and stochastic geologic models. Inferences from performance data, water injection profile surveys, well logs; Associated studies.
4	3	Reservoir Simulation - Development of deterministic and stochastic thermal reservoir simulation models to assist reservoir management.

5	4	Reservoir Management - Cyclic steam stimulation through horizontal wells; Steam drive through horizontal wells; and Hot-water-alternating-steam (WAS) drive.
6	5	Operational Management - Evaluating the alkaline hot water/steam well completion technique; Geochemical studies; High temperature core work for thermal reservoir simulation models.
7	6	Expansion Project - Scheduled to start in 1999
8	7	Technology Transfer - Activities to communicate knowledge and experience gained from the project.

The report emphasizes the activities which have been the most significant throughout the past year in terms of effort, monetary expenditure and interest within the petroleum community with regard to Technology Transfer activities:

1. Utilizing and extending the present 3-D deterministic geologic model in the development of a 3-D stochastic model;
2. Associated 3-D geologic modeling work;

3. Implementing and evaluating the pilot horizontal well steamflood and pilot Water-Alternating-Steam (WAS) Drive;

4. Evaluating a low-cost well completion technique using steam for formations with unconsolidated sands;

The project is being implemented by a team including:

1. The City of Long Beach - the operator of the field as trustee of the State of California-granted tidelands;

2. Tidelands Oil Production Company - the contract operator of the field for the City of Long Beach, and the party in charge of implementing the project;

3. The University of Southern California, Petroleum Engineering Program - consultants to the project, playing a key role in reservoir characterization and simulation; and

4. David K. Davies and Associates - Consultants to the project regarding petrography, rock-based log modeling, and geochemistry of rock and fluid interactions.

Expanding thermal recovery operations to other sections of the Wilmington Oil Field is a critical part of the City of Long Beach and Tidelands Oil Production Company's development strategy for the field. The availability of relatively inexpensive steam from an existing cogeneration plant and from a 50MM BTU/hr steam generator which can burn low BTU non-commercial produced gas, allows for economical thermal operations in the Wilmington Field with respect to the current oil prices. However, such favorable terms for obtaining steam are not expected in the future.

Future expansion of thermal recovery to other parts of the Wilmington Field will depend on improving the efficiency of heavy oil recovery, as is the intent of the project.

1.3 Development and Production History

The Wilmington Oil Field is the third largest oil field in the United States, based on the total oil recovered. Over 2.5 billion barrels of oil have been produced to date, from an original oil in place of 8.8 billion barrels.

The field is located in and around the City of Long Beach, in Southern California. Location maps of the field is in Figures 1.3-1 and 1.3-3. Figure 1.3-2 shows an aerial view of Fault Block II-A. The field is divided into ten fault blocks and seven major producing zones as illustrated in Figures 1.3-4 and 1.3-5. Heavy oil occurs in the Tar, Ranger and Upper Terminal zones. This project is being conducted in the Tar zone of Fault Block II-A.

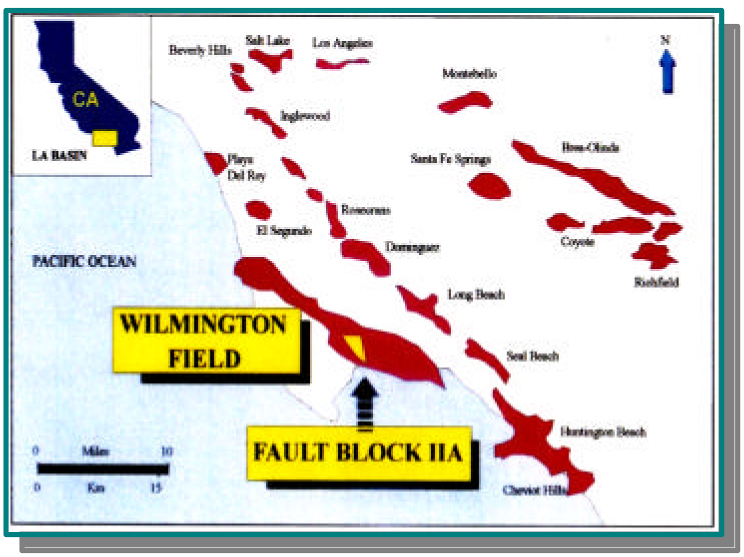


Figure 1.3-1 Map showing the geographical location of the Wilmington Field in Southern California.

Primary production from the field began in 1936. Waterflooding was introduced on a large scale during the 1950-60s to increase oil recovery and control surface subsidence. Various tertiary recovery projects have been tried since 1960, but with limited success. For most of the producing zones, waterflooding remains the dominant form of economic oil recovery. The current water cut is approximately 96%. Recoveries in the waterflood and tertiary recovery projects have been hindered by poor sweep efficiency, as is typical of SBC reservoirs with heterogeneous turbidite geology.

The Tar zone in Fault Block II-A began producing in 1937. Unitization for reservoir pressure maintenance and secondary recovery (waterflood) operations took place in 1960 and water injection began in that year. Cumulative oil production through 1979, after 19 years of waterflooding, was 20 million barrels; equivalent to a recovery factor of only 20% OOIP.

This low recovery factor was due to adverse mobility ratio and sand heterogeneity, which have resulted in low areal and vertical sweep efficiencies.

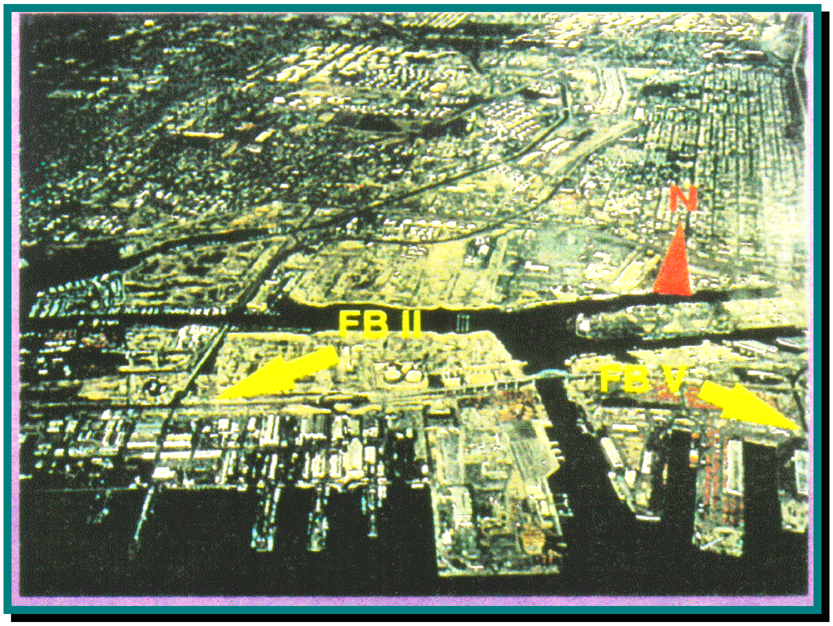


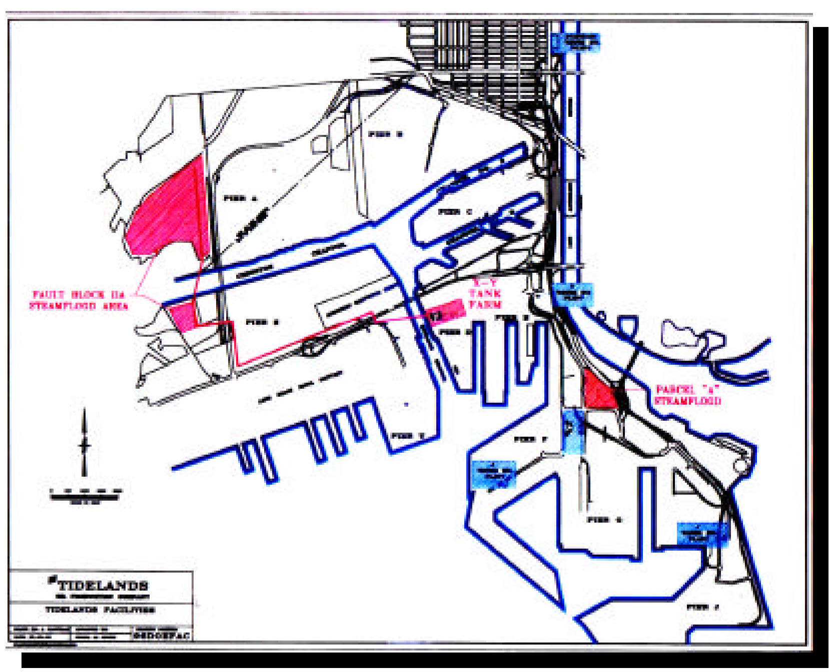
Figure 1.3-2 Aerial view of the Wilmington Field showing the location of Fault Block II-A.

Because of the poor performance of waterflooding, it was decided to evaluate the economics of applying steam injection to improve recovery of this heavy (13° API) oil.[A1]

A successful steam injection pilot test, comprised of four inverted 5-acre five-spot patterns, was carried out in the Tar zone of Fault Block II-A from 1982-1989.[D2] The pilot recovered 1.1 million barrels of oil, for a recovery factor of 75% of the oil-in-place in a previously Waterflooded area.

Figure 1.3-3 (right)

Plan view of Tidelands facilities showing the steamflood zone of Fault Block II-A, Wilmington Field.



The pilot was expanded to 150 acres using an inverted 7-spot pattern throughout the northern half of the fault block in 1989, but the expansion has not met with the same degree of success as the pilot. As of March 1997, the steamflood was producing 2618 b/d oil, 35,323 b/d of water, and 500 mscf/d of low BTU gas from the 49 wells. Steam injection was 31,000 b/d cold water equivalent into 39 injection wells. The cumulative steam/oil ratio is a high 8.5. Recovery efficiency has been relatively low due to poor sweep, with high water cut and early steam breakthrough. Operational problems have included scaling and premature equipment failure due to the high produced fluid temperatures accompanying steam breakthrough. Costly and inflexible completion practices were utilized to control sanding problems that have occurred elsewhere in the field. These are problems frequently encountered in the complex turbidite geology of SBC reservoirs in the Tar zone.

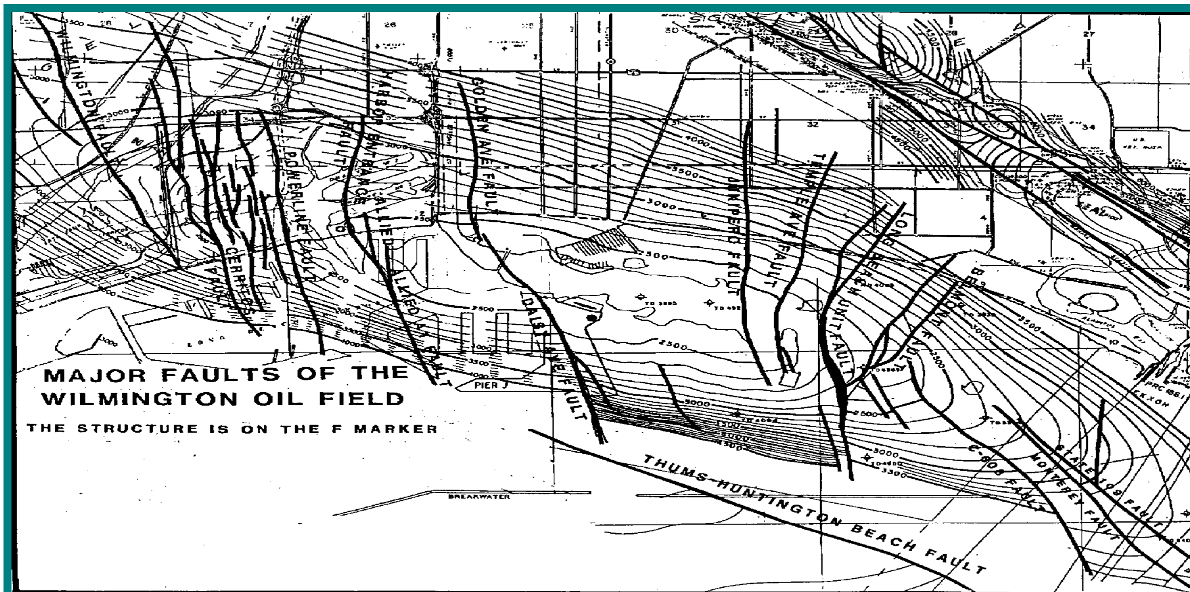
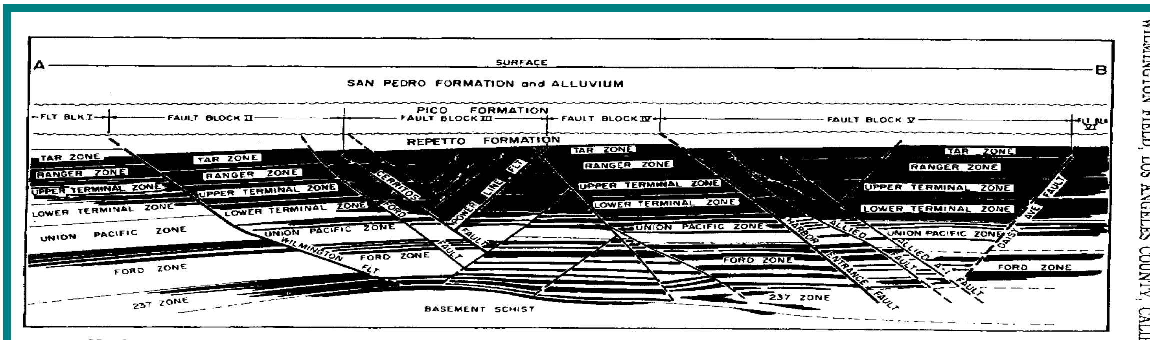


Figure 1.3-4 Geologic representation of the Wilmington Oil Field detailing fault line layout.



Northwest-southeast cross section, Wilmington field, showing producing zones. Trace of section is *A-B* on Fig. 1. Source—*California Oil and Gas Fields*, Pt. 2; courtesy California Division of Oil and Gas.

Figure 1.3-5 Cross section of a representative sector of the Wilmington field detailing producing zones.

1.4 Geologic Setting

The Wilmington Oil Field is an asymmetrical, highly faulted, doubly plunging anticline, eleven miles long and three miles wide. The productive area consists of approximately 13,500 acres. Fault Block II-A is located near the western edge of the field. It is bounded on the east by the Cerritos Fault and on the west by the Wilmington Fault. The north and south limits of the fault block are governed by water-oil contacts within the individual sand members of the various zones. The seven zones within each fault block listed in order of increasing depth are: Tar, Ranger, Upper Terminal, Lower Terminal, Union Pacific, Ford and "237".

Oil from the Wilmington Field and from throughout the Los Angeles Basin is produced mainly from Lower Pliocene and Upper Miocene age deposits. The Tar zone has the shallowest oil producing sands of the thick Miocene-Pliocene sequence. The Tar zone sands are lower Pliocene, middle Repetto formation lobe deposits.

The upper Miocene Puente and lower Pliocene Repetto formations within Fault Block II-A consist of interbedded sand/shale sequences belonging to submarine fan facies. These are considered to be bathayal, slope and base-of-slope deposits. The upper Miocene sands are intercalated with shales and slitstones in the form of widespread thin turbidites. Large lobate fans dominate the Pliocene section.

The Tar zone in Fault Block II-A consists of four major producing intervals exhibiting typical California type alternation of sand and shale layers as illustrated at right by the type log in Figure 1.4-1.

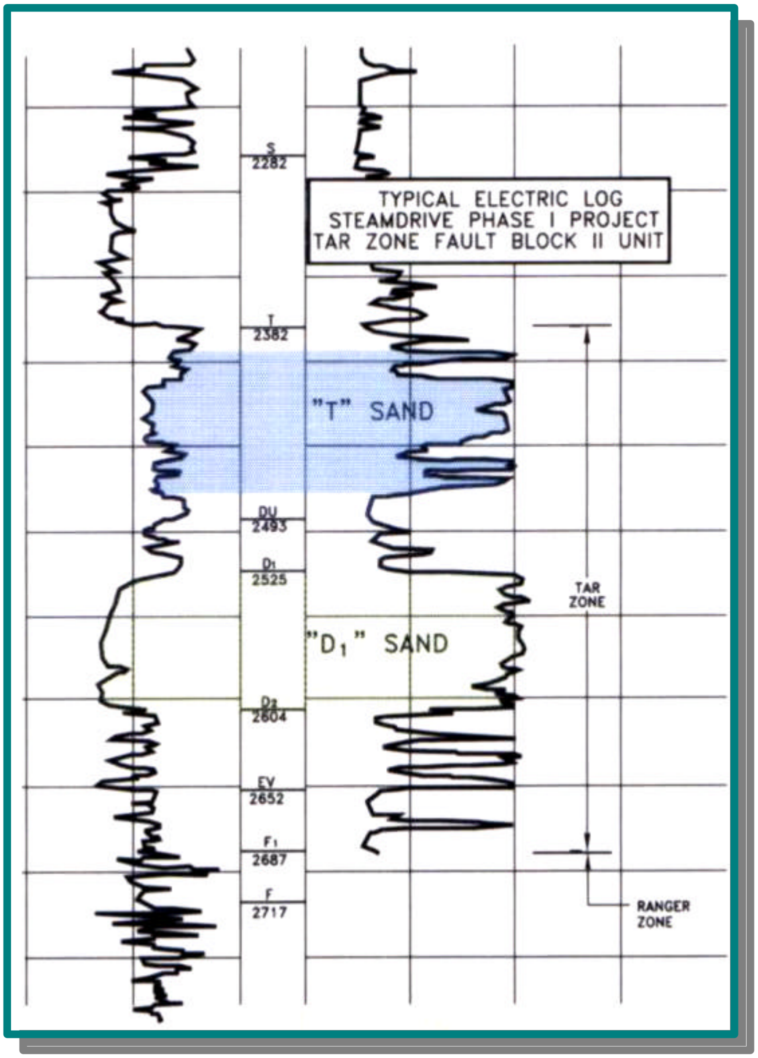


Figure 1.4-1 Type Log 1, Tar Zone, Fault Block II-A illustrating "T" and "D1" sands.

The Tar zone sands tend to be unconsolidated, friable, fine to medium-grained and contain varying amounts of silt. The thickness of the sand layers varies from a few inches to several tens of feet. Shales and siltstones are generally massive, with abundant foraminifera, mica, and some carbonaceous material. The shales are generally soft and poorly indurated, although there are thin beds of fairly firm to hard shale. The oil is of low gravity, ranging from 12-15^o API with a viscosity of 360 cp and an initial formation volume factor of 1.057 RB/STB. Based on available information, the Tar zone sands have an average porosity ranging from 30-35% and permeabilities ranging from 500-8,000 millidarcies with a weighted average of 1,000 millidarcies. Approximate zone thickness ranges from 250-300 ft. The top of the structure appears at a depth of 2,330 ft below sea level in Fault Block II.

2 COMPILATION AND ANALYSIS OF EXISTING DATA

2.1 Introduction

As with the previous year, existing field data were compiled, evaluated for reliability, and analyzed in terms of production response and constraints to provide a foundation for creating geologic and reservoir simulation models. The data were incorporated into Production Analyst ™ (PA) - a computer-aided data retrieval system by Geoquest - to facilitate simulation-based reservoir management.

The following tasks have been in progress from the previous year:

1. Retrieval and review of historical reservoir engineering data.

2. Development of a database of available well logs.

   Digitization and normalization of log data from 178 wells distributed throughout Fault Block II-A Tar Zone were completed during the previous year.

2.2 Data Compilation

A database of production and injection for the Tar Zone in Fault Block II-A from 1938 to the present was completed during the previous year. However, historical reservoir engineering data available from the City of Long Beach and Tidelands are still continually being retrieved and reviewed. The production and injection database and the historic reservoir engineering data are being used to support reservoir engineering for this project.

Within the previous work year, a rock-log model was completed. This, along with other 3-D models being developed, necessitated a more thorough review of past production and injection data, as well as cross comparisons with associated core samples.

The database was more difficult to digitize than anticipated because of the volume and age of the hard copy data, and because of the difficulty in determining how production and injection was allocated historically to zones and sub-zones in commingled wells.

In addition to digitizing the data needed for this project, Tidelands has been digitizing historic production and injection data from all of its operated wells in Fault Blocks I through IV. The production and injection database in its entirety will be made publicly available when completed in mid-1997.

2.3 Log Digitization and Normalization

A preliminary database identifying all logs run in each well penetrating the Tar zone II-A was completed.

Log data from 178 wells (up from 171 the previous year) distributed throughout the fault block were digitized, normalized and converted to Log ASCII Standard (LAS).[A3,A5] The digitized logs, including electric or induction logs and Spontaneous Potential (SP) and/or Gamma Ray (GR) logs, will be used for basic reservoir engineering and for development of the deterministic and stochastic geologic models. Directional data for the wells were also digitized and included in the database.

A total of 78 wells within the Tar zone have modern logs which were digitized. Logs digitized include the formation density, compensated neutron, dielectric as well as spectral gamma ray for some wells. Of the 78 wells, twelve were conventionally cored, including two observation wells drilled for this project. The data from the ten pre-DOE cored wells were instrumental in the derivation of the rock-log model, the core-based log model and the porosity-permeability model.[A21,A22] The two newest conventional cores, from wells OB 2-3 and OB 2-5, will be used to "confirm" the rock-log model.

Logs from an additional 100 wells (from the more than 600 wells which penetrate the Tar zone in Fault Block II) will be digitized and normalized to serve as "confirmation" logs for testing the stochastic geologic model. Logs to be digitized from these wells are currently limited to Spontaneous Potential (SP) and Resistivity.

2.4 Conclusion

A computerized database of historic production and injection data was completed to aid in reservoir engineering. The database has provided the means of accessing individual well records on a digital and graphical basis.

The database contains valuable rock and fluid properties for performing correlation studies in similar reservoirs in the Wilmington Field and other Los Angeles Basin oil fields and other SBC reservoirs.

Much of the thrust of the project this year involves the derivation of 3-D deterministic and stochastic models. As these models rely heavily on empirical data from the field, a thorough review of available data was initiated.

3 ADVANCED RESERVOIR CHARACTERIZATION

3.1 Introduction

Advanced reservoir characterization is considered to be a key element for improving oil recovery efficiency by allowing for optimum placement and completion of wells. Advanced reservoir characterization supplies the input for the stochastic 3-D reservoir simulation models needed for the effective design of thermal recovery projects. Reservoir characterization is an important tool for understanding steam breakthrough, which occurs in the Wilmington Field steamflood, and for providing economic solutions for improving reservoir sweep efficiency.

Basic reservoir engineering work was performed at the start of the reporting period.[A14,C10] Work was performed on evaluating the aquifer for water influx and determining the original oil in place from gas production data to support the material balance work. Work completed includes: an analysis on the primary and waterflood recoveries; permeability estimates from performance data; comparing and quality checking the water injection profile surveys to the allocated injection volumes for each sub-zone[A4]; determining the quality of the new and old well logs; determining the vertical communication between sands; evaluating the aquifer and solution gas; and performing correlation studies on projected steam recoveries from vertical and horizontal wells.

A petrophysical rock-log model was completed by the first quarter of the work year.[A21-22.C6,C32] The model involves a detailed analysis of cores sampled from ten wells and their associated well log responses from the Tar zone in Fault Block II-A of the Wilmington Field. The formation wells were classified into different rock types using data from petrographic image analysis, and integrating this data with the results of an analysis of environmentally corrected and normalized well log responses. The rock-log model is able to generate a relationship between permeability and porosity for a specific rock type, and extrapolate the relationship to model permeability for the specific rock type in locations where only well log data are available. Thus, this relationship can be extended to predict future production data. The procedure is both economic and rapid as no new evaluation wells, specialized logs and well shut-ins are required.

A 3-D deterministic geologic model was completed[A6-8,A10-13,B7,C1,C11,C14-17,C20,C25] and a stochastic model is being developed to describe the heterogeneous turbidite geology of the Fault Block II-A Tar zone. These models will aid in delineating geological controls of reservoir dynamics, conceptualizing reservoir architecture, and identifying remaining oil.

Data for the geologic models are being derived from various sources, including existing logs from over 600 wells which penetrate the Fault Block II-A Tar zone, detailed petrographic studies of cores, Measurement-While-Drilling (MWD) data from the installation of four new horizontal wells, open hole logs from five observation wells, and a tracer study. Dynamic characteristics of the formation are being incorporated into the geologic models based on analysis of past performance data and the tracer and pilot tests to be performed during Budget Period I. The geologic models are being visualized using EarthVision™ imaging software, by Dynamic Graphics, Inc, to facilitate future reservoir analysis and interpretation.

The 3-D deterministic geologic model correlates eighteen different sand layers in the Tar zone. Existing cores were inspected before determining their suitability for the derivation of a core-based log model, a porosity-permeability model and a rock-log model.

The stochastic geologic model is expected to result in improved performance predictions over the current existing 3-D deterministic model. The stochastic model involves data integration of the 3-D deterministic geological model, sediment modeling analysis, well logs and core data as well as data made available through the basic reservoir engineering study.

Application of detailed, geologically realistic reservoir models based on stochastic concepts has increased in the petroleum engineering community in recent years. The stochastic model is essentially a quantitative geologic model with arbitrary scales of resolution. Because the data from cores or well logs are only available at well locations, there is a need to assign flow properties to other unsampled locations. Geologic models should be able to match data measured at sampling points and resemble the significant reservoir properties at unsampled locations. Various levels of model creation will be employed to incorporate facies architecture, local flow properties, and distribution of discontinuous shales.

Other activities of note include: a detailed sand sequence analysis of the geologic column in the Tar zone is being conducted to map local depositional effects requiring special correlation studies during the conceptual modeling phase[A23]; a parametric study on the projected steam drive recoveries from vertical and horizontal wells was initiated in the third quarter of the work year[A15]; a reservoir tracer program was initiated in the hot water injection wells; and high temperature core work was initiated to measure steamflood recovery potential, oil and water permeability data, thermal rock compaction and erosion and to determine formation rock and fluid alterations due to steamflooding.

Key tasks completed during this reporting period include:

1. Performing basic reservoir engineering studies.

2. Evaluating reservoir data to determine its suitability for use in the derivation of 3-D models.

3. Development of a petrophysical rock-log model.

4. Preparation of SPE papers for the 1997 Western Regional Meeting of the Society of Petroleum Engineers detailing the basic reservoir engineering work performed and the rock-log model.

3.2 Basic Reservoir Engineering

Table 3.1a lists the rock and fluid properties, which were used in reservoir characterization.

Table 3.2a - Average Reservoir Properties	
Average Rock Properties	
Porosity, %	34
Initial Water Saturation, %	21
Air Permeability, md	1800
Total Tar Zone Thickness, ft	250
Total Hydrocarbon Thickness, ft	125-150

Average Fluid Properties	
Original Temperature, ^oF	126
Original Pressure, psig	1110
Oil Gravity, ^oAPI	13-14
Original Gas Gravity (air=1)	0.59
Initial Solution GOR, scf/stb	97
Initial Formation Volume Factor, bbl/stb	1.06

3.2.1 Evaluation of aquifer for evidence of water influx in Fault Block (FB) II-A

Primary production data for the Tar zone FB II-A was analyzed from production inception in 1937 to 1960 to determine the magnitude of water influx from the aquifer. Waterflooding in 1960 signaled the termination of the primary production phase of the Tar zone. Bubble maps of water production prior to 1960 were thus evaluated.

Previous studies have shown no indication of cross-flow between the Tar zone and adjacent zones, which is consistent with the findings in this study. Therefore evidence of water influx is limited to the southern or northern flanks of FB II-A.

Overall, water influx is significant during the primary production phase in the Tar Zone FB-IIA. Table 3.1b shows the primary water recovery over time in terms of water-oil ratio, fractional flow of water and cumulative water produced. Figure 3.2-1 shows the bubble map representation of the cumulative water production prior to the onset of water injection, for producers with greater than 100M stock tank barrels (STB) of cumulative water production.

Table 3.2b - Natural Water Influx			
X-Plot Calculations for Northern Section of FBII-A			
Year	WOR	f_w	W_i(MMbbl)
1955	1.1	0.533	3.55
1956	1.4	0.583	3.63
1957	1.8	0.649	3.88
1958	2.2	0.690	4.13
1959	2.7	0.730	4.70
1960	3.6	0.783	5.18
X-Plot Calculations for Southern Section of FBII-A			
Year	WOR	f_w	W_i(MMbbl)
1953	1.3	0.565	2.87
1954	2.0	0.666	3.18
1955	2.4	0.706	3.40
1956	2.9	0.743	3.70
1957	3.2	0.760	3.87
1958	4.0	0.800	4.42
1959	4.8	0.827	4.94
1960	6.7	0.870	6.03

3.2.2 Determination of Original Oil-in-Place (OOIP) from Material Balance as a Straight Line

The volumetric method was utilized. This entailed estimating the average hydrocarbon thickness and a constant porosity. The material balance equation as a straight line can be written as:

$$F = N(E_o + E_{fw}) + W_iB_w \quad \text{----------------} \ (3.2.2a)$$

Where,

N = initial oil in place (stb)
E_o = oil expansion factor (bbl/stb)
E_{fw} = formation water expansion factor (bbl/stb)
W_i = cumulative water influx (bbl)
B_w = water formation volume factor (bbl/stb)
F = net reservoir production (bbl)

Dividing both sides of the equation by $(E_o + E_{fw})$ yields a straight line,

$$\frac{F}{(E_o + E_{fw})} = N + \frac{W_iB_w}{(E_o + E_{fw})} \quad \text{-----------------} \ (3.2.2b)$$

Thus, the graph can be extrapolated to $(W_iBw)/(E_o + E_{fw}) = 0$, and N can be obtained.

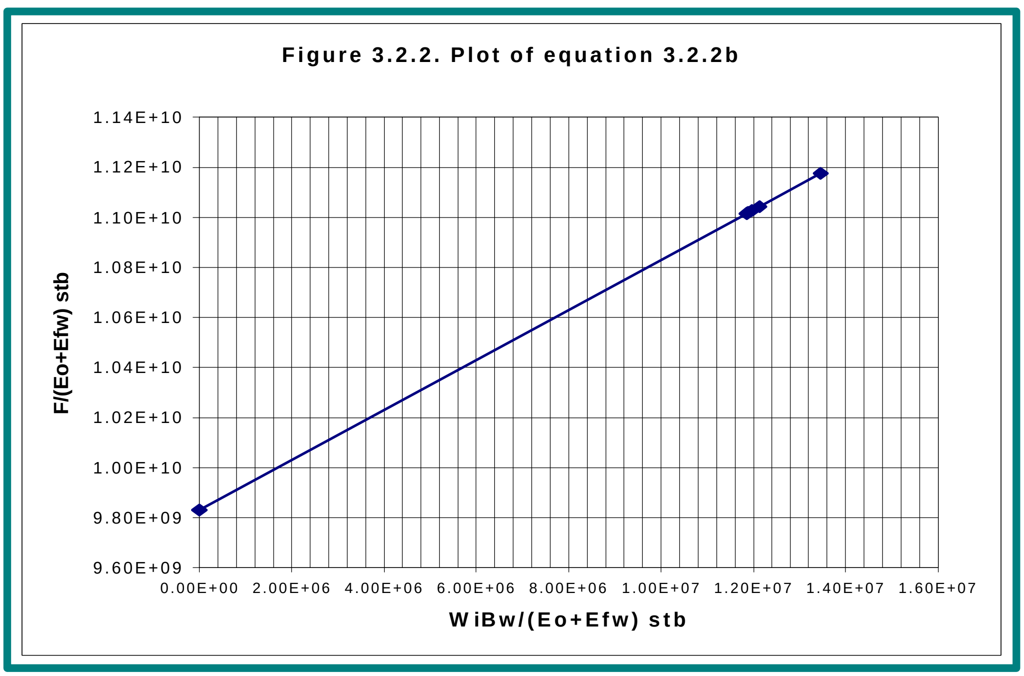


Figure 3.2.2 Plot of equation 3.2.2b

Thus, it can be seen that a value of 98.3MMstb is obtained when $(W_iBw)/(E_o + E_{fw}) = 0$.

Table 3.2c – Values used in the material balance calculations					
	F (MMbbl)	E_o (bbl/stb)	E_{fw} (bbl/stb)	W_i (Mbbl)	B_w (bbl/stb)
1955	5398	0.4576	0.0254	6500	1.0
1956	6670	0.5580	0.0460	7330	1.0
1957	7564	0.6102	0.0762	8160	1.0
1958	8280	0.6565	0.0944	8990	1.0
1959	9124	0.7155	0.1128	9820	1.0

3.2.3 Determining Original Oil-in-Place (OOIP) from Gas Saturations

In this study, the assumption was made that the original reservoir pressure was restored from a low of 265 psig after initiating water injection. Thus, the free gas saturation is essentially zero. Therefore, gas remaining in the reservoir since the start of the waterflood has been in solution at the minimum reservoir pressure. From these premises, a rough estimate of the OOIP by way of the cumulative gas produced, during the primary production phase, can be obtained.

Gas production prior to the start of the waterflood in 1960 is 73% of the cumulative production based on the ratio of the minimum reservoir pressure against the original reservoir pressure. Uncertainties about the validity of the measured gas production are a concern, as gas prices at the time of interest did not warrant accurate bookkeeping.

Thus the following relation was used:

$$N = \frac{G_p}{R_{si}\frac{(P_i - P_{min})}{P_i}} \quad \text{----------------- (3.2.3a)}$$

Where G_p is the cumulative gas produced, R_{si} is the initial solution gas-oil ratio, P_i is the initial pressure, P_{min} is the minimum reservoir pressure (i.e. prior to the start of waterflooding) and N is the estimate for the amount of original oil in place.

The methodology described above yields 98.3MM STB of OOIP, using G_p = 7.16MMMscf; R_{si} = 97 scf/stb; P_i = (1110 + 15) psia; P_{min} = (265 + 15) psia.

3.2.4 Analysis of the Primary and Waterflood Recoveries

An extension of the calculations was performed to estimate the recovery factors using OOIP values. Both methods yielded 10% recovery prior to the onset of waterflooding, 22-23% recovery at the initiation of steamflooding in 1982 and 31-33% recovery through 1995, the most recent production data available in database.

The total amount of liquid and gas produced, under primary conditions, from the Tar zone FB II-A is 18.5MMbbl liquid and 7.16MMMscf gas. It is assumed that the reservoir is not fully under water drive mechanism.

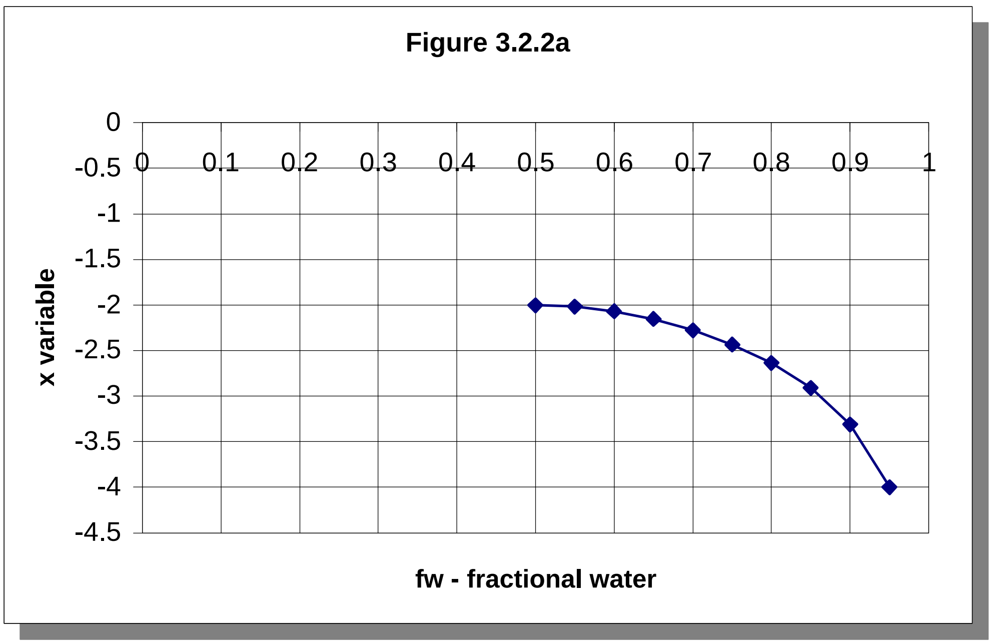
3.2.5 Permeability Estimates from Performance Data by x-plot technique

The permeability of the various zones in FB II-A can be estimated by an extension of the x-plot technique, which proposes a linear relationship between the fractional water cut (f_w) and fractional recovery (E_R), such that

$$E_R = mx + n, \qquad \text{---------------- (3.2.5a)}$$

And, $$x = \ln(1/f_w - 1) - 1/f_w \qquad \text{--------------- (3.2.5b)}$$

Figure 3.2-5a shows equation 3.2.5b in graphical form.



3.2-5a Graphical representation of equation 2. Conversion of fractional water to dimensionless fractional water.

Where m and n are constants which are dependent on a and b.

$$m = \frac{1}{b(1-S_{wi})} \qquad \text{-------------- (3.2.5a)}$$

$$n = \frac{1}{(1 - S_{wi})}\left[S_{wi} + \frac{1}{b}\ \ln\left(a\,\frac{\mu_w}{\mu_o}\right)\right] \qquad \text{-------------- (3.2.5b)}$$

Where,

S_{wi} = initial water saturation

μ_w = water viscosity (cp)
μ_o = oil viscosity (cp)

a and b are constants of the following equation,

$$\frac{k_{rw}}{k_{ro}} = -\frac{1}{a}\, e^{-bSw} \qquad \text{-------------} \ (3.2.5c)$$

Where,
k_{rw} = relative water permeability
k_{ro} = relative oil permeability

Thus, a curve can be obtained relating krw/kro to the water saturation.

In the x-plot technique, the water saturation is defined as the current value at the producing end, rather than the average field saturation. Thus, one should convert the calculated average water saturation into producing end saturation by applying the following formula.

$$S_{we} = S_w - \frac{W_i}{V_p}(1 - f_w) \qquad \text{-----------------} \ (3.2.5d)$$

Where,
S_{we} = producing end water saturation
S_w = average water saturation
W_i = cumulative water influx bbl
V_p = pore volume bbl

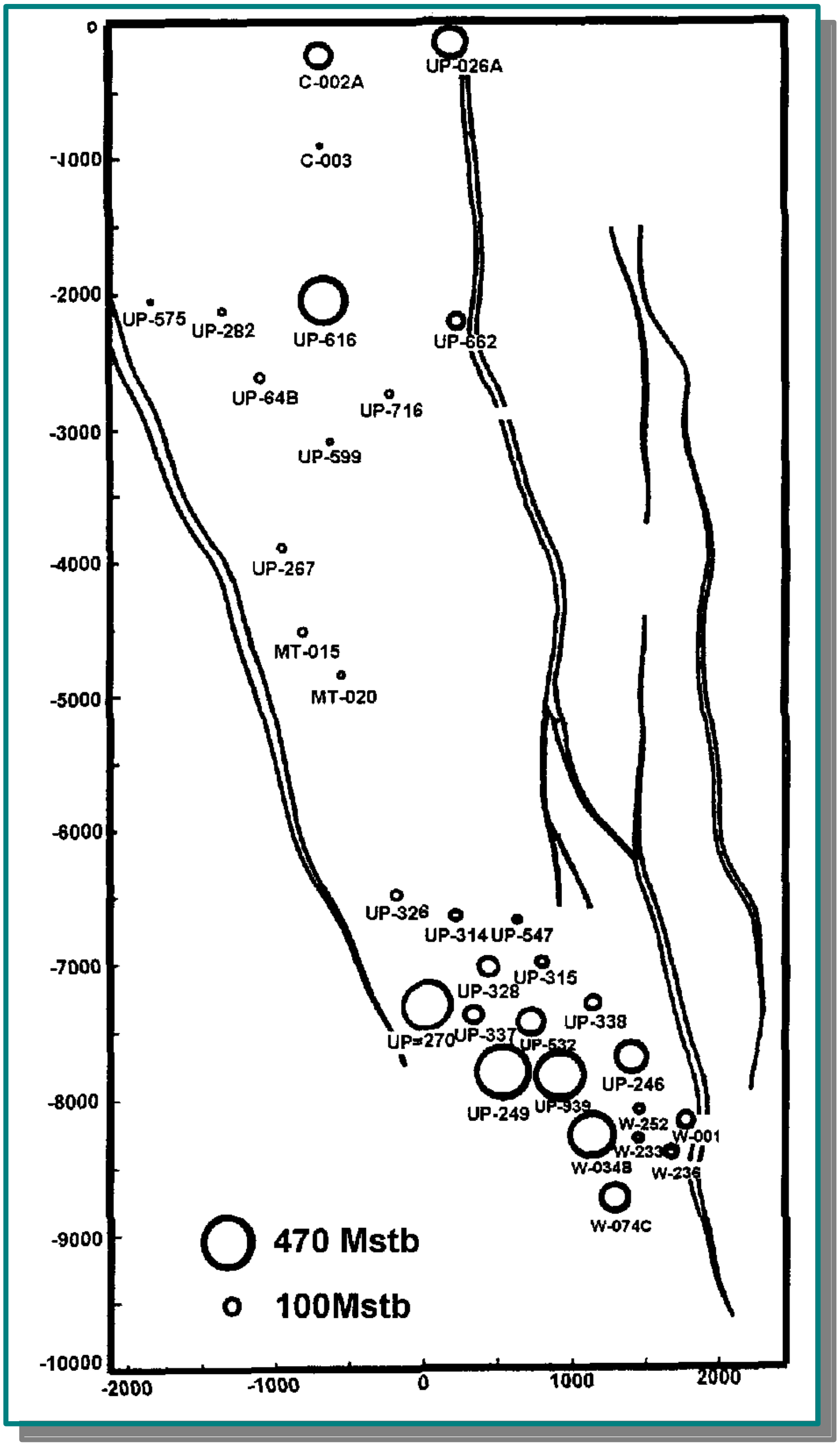


Figure 3.2-5b Bubble map representation of cumulative water production prior to waterflood initiation in 1960.

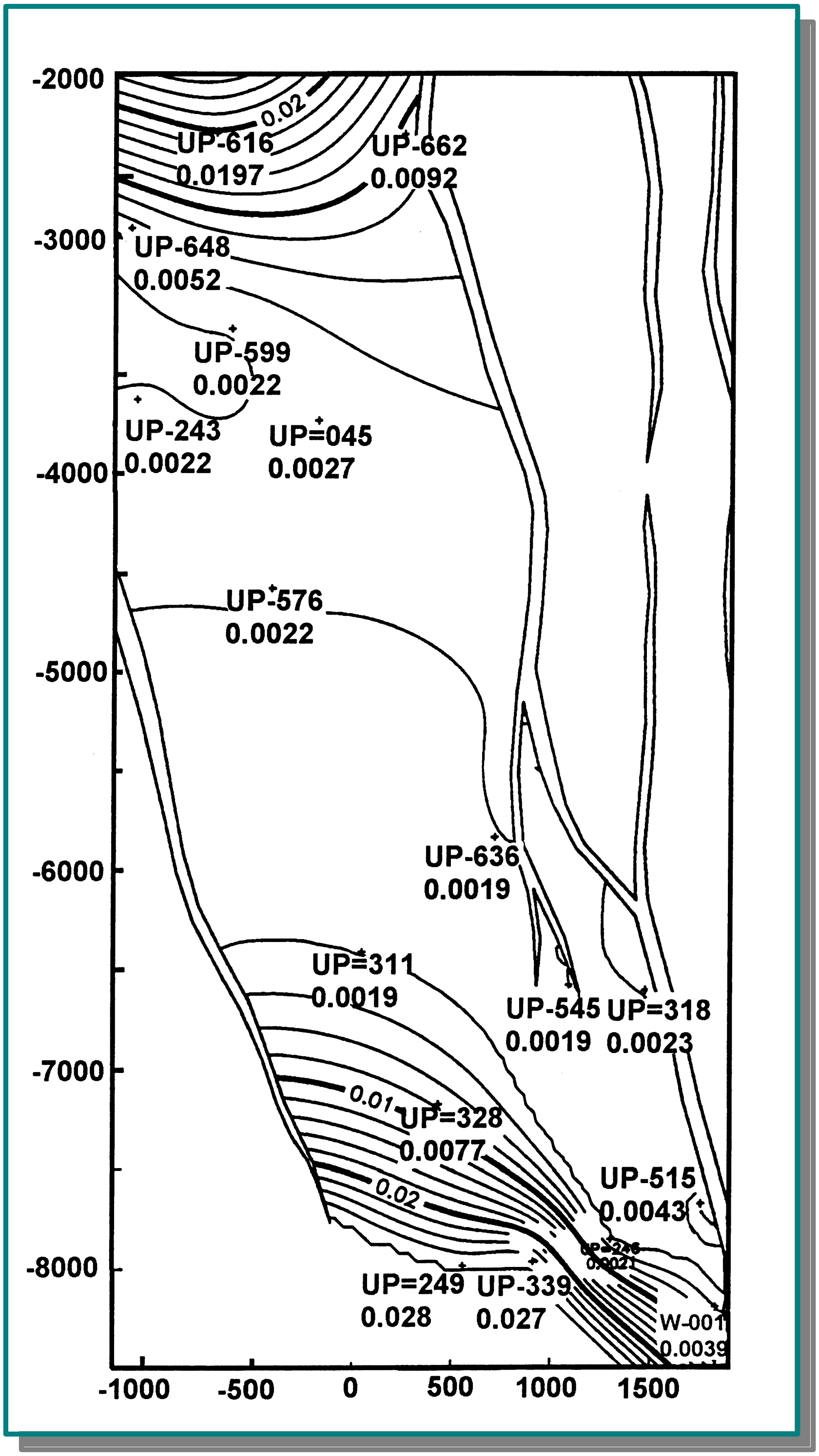


Figure 3.2-5c Water-Oil Permeability Spread for Fault Block II-A, Wilmington Field

Using this correlation, the composite effective permeability maps in Figure 3.2-5b can be converted into a saturation map. Correspondingly, the water saturations in the Tar zone prior to the start of waterflooding are: 23% in the center; 26% in the southeast; 31% in central north, and 33% in the south of FB II-A. Prior to the start of waterflooding, the time averaged water saturation in the central part of the field was not much different than the initial water saturation at 21%. However, an increase in 12% and 8% in the southern and central northern parts respectively was observed as a result of natural water influx.

Figure 3.2-5c details the resultant Water-Oil Permeability spread for Fault Block II-A in the Wilmington Field. This is the result of applying the x-plot method to directly convert saturation profiles into permeability maps.[C19]

3.2.6 Estimation of Cumulative Oil Produced from Water Influx data

Figure 3.2.5a details the graphical conversion of fractional water (f_w) into the x variable. The water influx can be obtained from:

$$W_i = \frac{-B_{oi}}{mf_w(1-f_w)} \qquad \text{---------------- (3.2.6a)}$$

Where,

m is the slope of the cumulative oil produced versus x curve and has 1/surface unit. Thus, the cumulative production can be obtained if W_i and f_w are known.

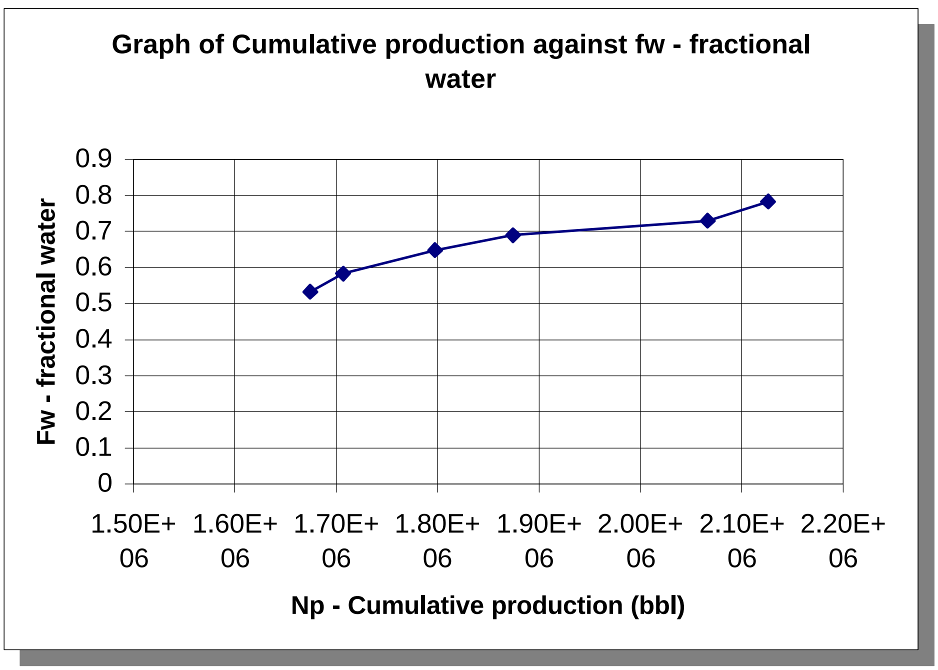


Figure 3.2-6 Cumulative production for Northern section, Fault Block II-A.

3.2.7 Comparison of water injection profile surveys to injection volumes in sub-zones

Waterflooding was initiated in FB II-A in Feb. 1960 with the injection of water into the T, D1 and D2 sands from well 2ATR-001. Each of the 10 surrounding production wells were producing approximately 20 barrels per day of oil with a 40-50% water cut at the start of the waterflood. This was used as the justification for assuming uniform oil and water saturation at the commencement of injection. The water injection rate was kept constant at 1,050BPD. The approximate allocation of water to layers was 71% T, 22% D1 and 7% D2, from profile surveys. Correspondingly, assuming uniform porosity, T possesses the highest conductivity and D2 the lowest. In March 1961, water injection was initiated in wells 2ATR-002, 2ATR-003 and 2ATR-004. However, injection rates to these wells varied with time.

Derivative plots based on cumulative water cut (hence, cum-derivative) were used to demonstrate successive breakthroughs. The cumulative water cut is defined in terms of cumulative oil and water production data.

Figure 3.2-7a at right shows the cum-derivative of four producers surrounding the 2ATR-001 water injector. The distance from the injector to each well was about the same. Each of the producers experienced 5 successive breakthroughs.

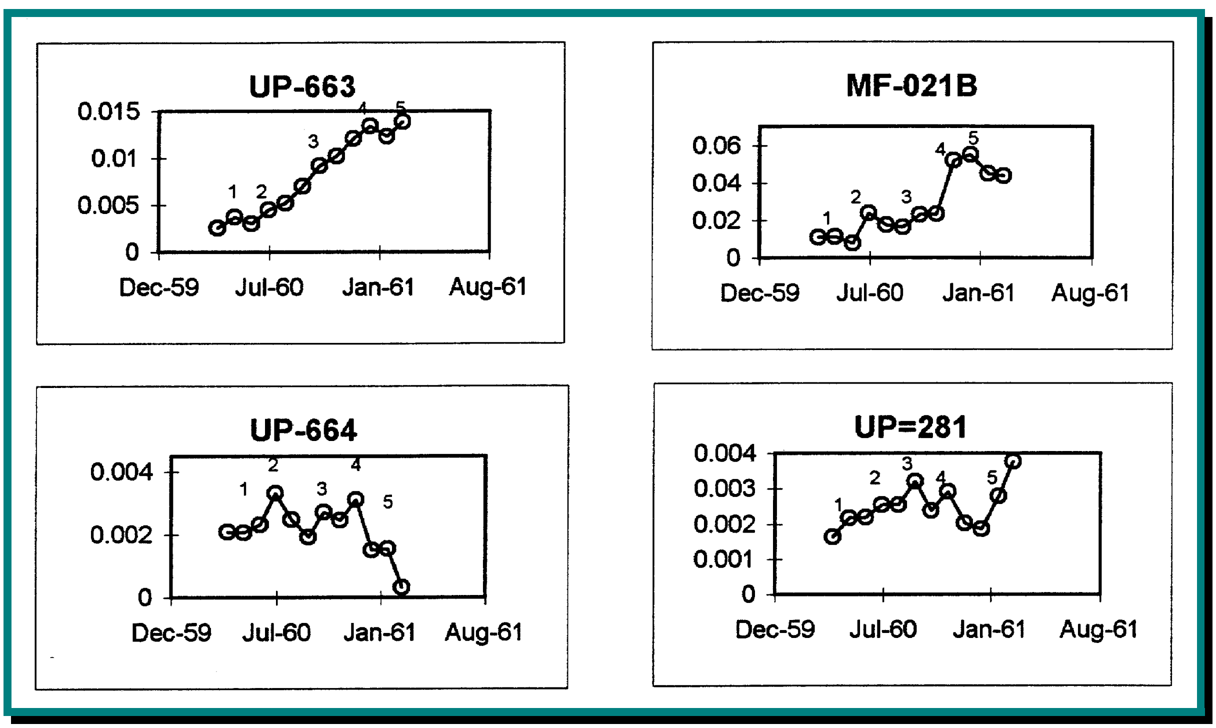


Figure 3.2-7a Cumulative Derivative Plots of 4 producers surrounding 2ATR-301. The 5 successive breakthroughs are numbered.

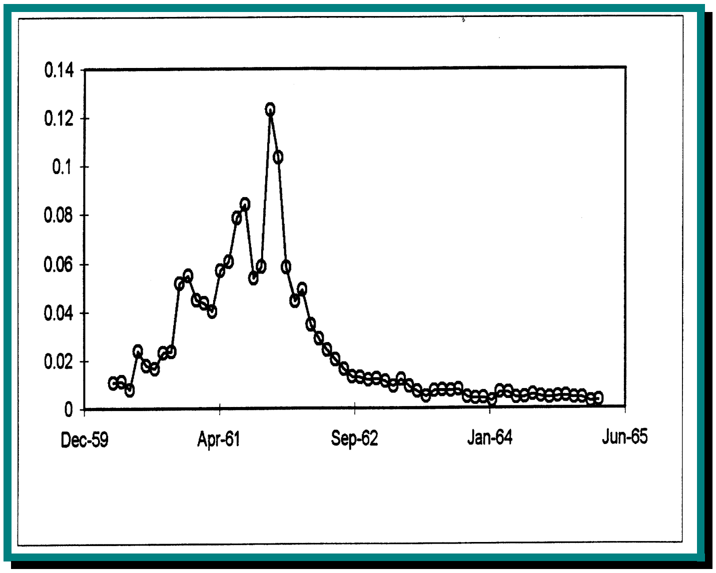


Figure 3.2-7b Cumulative derivative plot of producer MF-021B showing 5 successive peaks.

This is indicative that the reservoir possesses five layers with distinct permeability properties. Further study of the vertical locations of the layers requires more extensive geological knowledge of the Tar zone in FB II-A. The cum-derivative plots identified 5 of 18 known distinct layers in 3 sub-zones. Thus, it is evident that there are unswept layers which potentially contain bypassed oil. Injection profile surveys can reconfirm which sands received water from injection.

A 5-year production history of producer MF-021B was carried out. The cum-derivative plot shows a total of twenty successive breakthroughs for four injectors. (Figure 3.2-7b).

The layers increase proportionally with additional injectors, which is consistent with our previous findings of five distinct sands responding to waterflood injection.

Figure 3.2-7a also shows that breakthrough times are similar for the production wells in question. Either there is little or no directional preference of the layers or a fractional flow curve based on monthly data is inadequate for an analysis of breakthrough times. [37]

3.2.8 Determining the quality of new and old well logs

As the available well log data is instrumental in the construction of the 3-D deterministic and stochastic models, it is essential that the quality of the well logs be evaluated. Past well cores obtained from the Tar zone of Fault Block II-A were evaluated for their suitability in the derivation of the rock-log model.

3.2.9 Evaluating the aquifer and solution gas

As has been mentioned previously, the aquifer was evaluated utilizing pre-1960 logs to determine the contribution to natural water influx before the commencement of water drive in the Tar zone of FB II-A. As with previous studies, no cross-flow between the Tar and adjacent zones was observed, therefore is was concluded that water influx was exclusively from the northern and/or southern edge of FB II-A. With reference to the bubble map in Figure 3.2-5b, it was noted that water movement was apparent at the northern and southern ends.

It was therefore concluded that natural water influx is a significant drive mechanism in the Tar zone of FB II-A.

Evaluation of the solution gas was deemed essential for the determination of initial oil in place (OOIP). Traditional electric log, core and drill-stem data did not provide adequate data as cores from unconsolidated sandstone reservoirs encountered a significant change in properties during coring, handling and testing. Calculating initial OOIP using the “cumulative gas produced” method provides a reasonable estimate that can be compared to the material balance method . A deduction of the gas produced during the primary period depended on the initial gas saturation of the oil. During the waterflood period, it was assumed the gas was totally in solution and was produced at a constant GOR for solution gas at 265psi.

3.3 Obtaining New Characterization Data

3.3.1 Comparison of Steam Drive Recoveries from Vertical and Horizontal Wells

The parametric study comparing projected steam drive recoveries from vertical and horizontal wells was almost completed at the end of the work year.[A15] The study attempts to compare recovery from both types of well completions as a function of reservoir properties, crude oil characteristics, and injection strategies. Study results using the TETRAD™ thermal reservoir simulator program - a product of Dyad 88 software Inc., are being cross-checked with the CMG (Computer Modeling Group) STARS™ program.

The study results will compare recovery from both types of well completions as a function of reservoir properties, crude oil characteristics, and injection strategies and provide guidelines and correlations for predictive purposes in developing the stochastic reservoir simulation model on the STARS program. The pseudo-Steam assisted gravity drainage (SAGD) method developed by Butler will be employed on horizontal wells (UP-955 & UP-956) and injectors (2AT-61& 2AT-63) in the Tar zone of Fault Block II-A. The study is expected to be completed during the next reporting period.

3.3.2 Reservoir Tracer Program

Reservoir tracers were bulk injected on 14 February 1997 into two hot Water-Alternating-Steam (WAS) pilot injectors, which are now injecting hot water. The tracer program includes two tracers, ammonium thiocyanate (AT) and lithium chloride (LC). The AT tracer slug consisted of 4,000 gallons of solution with a 54% AT concentration by weight, which was injected into the “T” sub-zone in Well 2AT-32.

The LC tracer slug consisted of 4,000 gallons of solution with a 22.5% LC concentration by weight, which was injected into the “D” sub-zone in Well 2AT-33.

The tracers will follow the liquid phase of the injected fluids rather than the steam phase and were selected based on their stability when exposed to high temperatures, minimum absorption rate and non-radioactive characteristics. Computer software has been developed to map formation permeability in 3-D from production and injection data. The software has been tested using a compositional model at a major research facility in California.

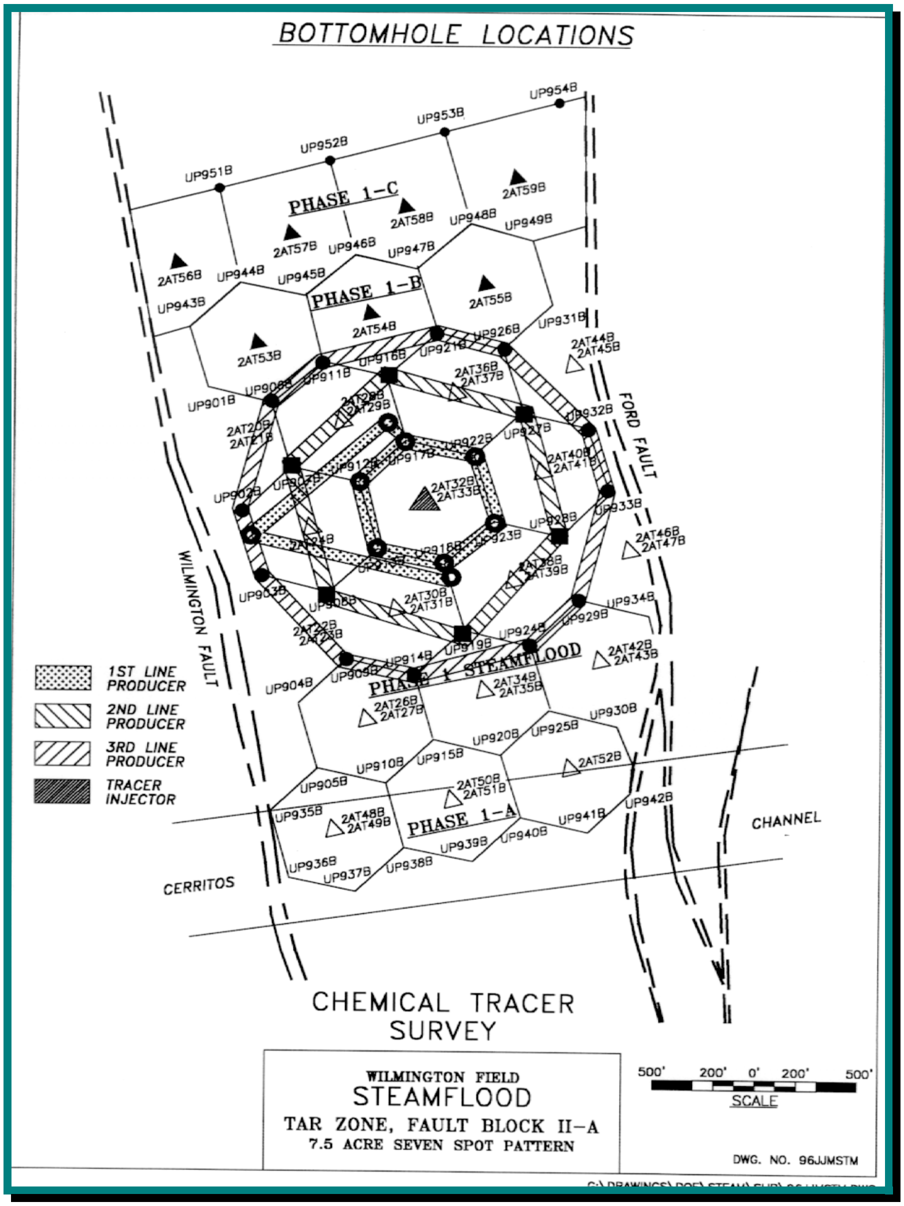


Figure 3.3.2 Plan view of bottomhole locations and associated zones of interest. Chemical Tracer Survey.

3.3.3 High Temperature Core Work

High temperature core work was begun on measuring rock compaction due to steamflooding. This aspect of the core work was added to the original proposal to perform steam pot tests and measure the geochemical effects of high temperature steam on the reservoir rocks and fluids which will be started the next reporting year. All of the special core work above will be used in the thermal reservoir simulation model.

3.4 Three-Dimensional Modeling

3.4.1 Introduction

This section aims to describe all forms of 3-D modeling accomplished or in progress. Associated work as well as projected and current usage of existing models will also be detailed.

The geological complexity of the Tar zone in Fault Block II-A requires 3-D modeling to better understand the lateral and vertical continuity of the reservoir. The problems associated with steamflooding can be remedied to some extent, with a better understanding of the geological controls on flow through the reservoir. The lobated nature of sand sequences in turbidite sands - such as those encountered in the Tar zone - necessitates a more thorough understanding of sand sequences. Hence a sand sequence analysis was carried out.

A petrophysical rock-log model was completed within the current reporting period.[A21-22,C6,C32] This model provides a consistent procedure for identifying formation rock types in wells using only log data. The rock-log model was developed by correlating the logs and conventional cores from ten wells in the Tar II-A zone. The conventional cores were analyzed for rock type based on pore throat size. Five rock types were identified, ranging from Rock Type 1 for sands with excellent permeability to Rock Type 5 for shales. The first three rock types are considered commercial quality reservoir rocks. Associated work involves establishing a separate porosity-permeability relationship for each rock type, thereby allowing the use of porosity logs for calculating permeability.

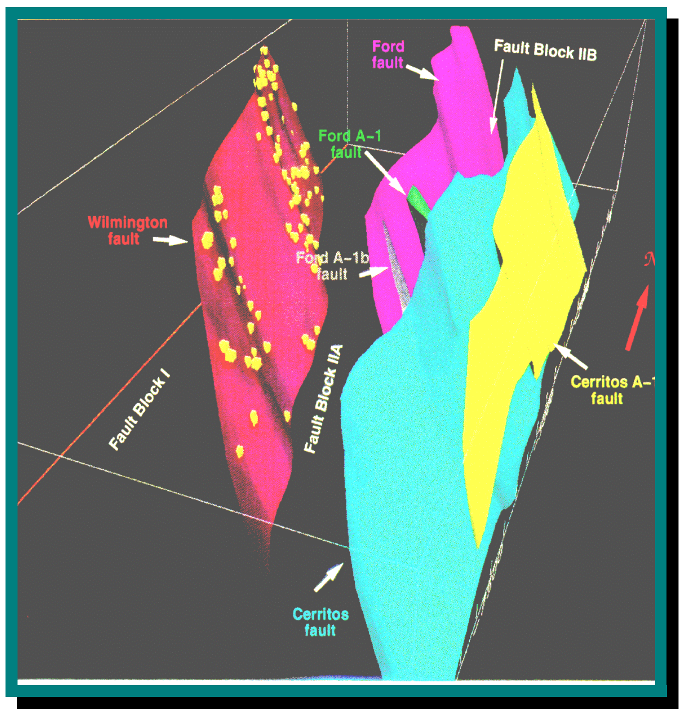


Figure 3.4-1 A Three-Dimensional view of the layout of associated faults which define the Fault Block II region.

The rock-types were defined using visual and thin section analyses of every foot of core. Each rock-type covers a wide range of pore throat sizes and permeabilities and is not meant to discern every grain size change in a turbidite sequence. This rock-log model was used to identify the distinct permeability layers in Fault Block II-A, Tar Zone for reservoir simulation modeling. Rock-typing is also limited to the accuracy of the induction, density-neutron, gamma-ray and spontaneous potential logs in determining bed thicknesses and sand quality.

The stochastic model is still in progress at the termination of the current reporting period. The stochastic model is expected to add significantly to our current understanding of the geologic controls on production and offer more realistic representation of the reservoir for simulation purposes.

3.4.2 Determining the vertical communication between sands

A sand sequence analysis of the geologic column in the Tar zone is being carried out to map local effects requiring special correlation studies during the conceptual modeling phase. Of particular interest was the observation that log normalization and environmental correction work can significantly and incorrectly affect log character with regard to variogram modeling. After environmental corrections are performed on the logs, it is critical that log normalization efforts are focused on correcting abnormal log responses and not "normalizing out" actual changes in facies distribution.[A3,A5]

3.4.3 Neural Network Model

The neural network model is being upgraded to analyze the similarities of various zones and sub-zones in terms of sequence stratigraphy using gamma ray, spontaneous potential, neutron and resistivity logs and to improve signal compression through linear transform techniques such as DCT, Fourier Transform, and DST. In an effort to improve the training process of the pattern recognition phase of the neural network model, procedures such as Self-Organize and Adaptive Resonance Theory and K-means were studied. Work also continued on development of submarine fan facies models. [A24]

3.4.4 Rock-Log Model and Porosity Permeability Relationship

The motivation for this study is to analyze improved techniques for the prediction of permeability and flow unit distribution in a high porosity, heterogeneous sandstone, such as that found in the Tar zone of Fault Block II-A in the Wilmington Field. This is accomplished by the identification of intervals of rock with unique pore geometry, referred to as a Rock Type.

The associated tasks performed for the eventual development of the model includes, but is not limited to:

i) Routine measurements of porosity and permeability, undertaken by an independent core analysis laboratory.

ii) Detailed macroscopic core description to identify vertical changes in lithology for all cores.

iii) Petrographic analysis of 100 small rock samples taken from the same locations as the plugs used for routine core analysis. The analysis included thin section point count, X-ray diffraction and scanning electron microscope analysis (secondary electron imaging mode - SEI). This provided a direct measurement of Vshale, Vclay, and grain size, sorting and overall composition for the 100 core samples.

iv) The identification of Rock Types based on: pore body size measured directly during automated image analysis in the scanning electron microscope on back scanner electron mode; pore throat size, as determined by direct measurement from the scanning electron microscope (SEI mode), and; by capillary analysis of selected samples.

iv) Algorithms were developed that relate porosity and permeability for each Rock Type in cored wells.

v) Log analysis, performed using normalized and environmentally corrected logs. The log shale indicators were calibrated to data from petrographic analysis, specifically Vshale from thin section, to allow for improved accuracy in the determination of porosity.

vi) Identification of Rock Types, using log responses in cored intervals, and comparison with core data.

vii) Extension of Rock Types, using log responses in cored intervals, and comparison with core data.

viii) Extension of the rock-log model to all wells with sufficient logs in the field. Specific algorithms were developed that allow for the identification of Rock Types from log data.

ix) Prediction of permeability, foot-by-foot in all wells using algorithms that relates porosity to permeability by Rock Type.

New efforts will be focussed to refine these correlations using core data from two wells, OB2-3 and OB2-5.

Using the old core analysis data to plot permeability versus porosity for the Fault Block II-A Tar Zone results in a poor correlation as shown in Figure 3.4.4-1.

An improved permeability versus porosity relationship is possible by classifying each foot of core and log by its rock type. Five distinct Rock Types (shown in Figures 3.4.4-3(a-d) have been isolated by the results of image analysis of pore body and pore throat size. Rock Type 5 does not feature on the porosity/permeability plot as it is defined by a region in which permeability is less than 0.01 millidarcies. Rock types 1 through 4 were identified using a cross-plot of apparent grain density versus the logarithm of the absolute value of the separation between Rxo and Rt.

Rock type 5 was identified using the gamma ray logs. Rock Types can therefore be identified, foot-by-foot in all wells with a sufficient logging suite.

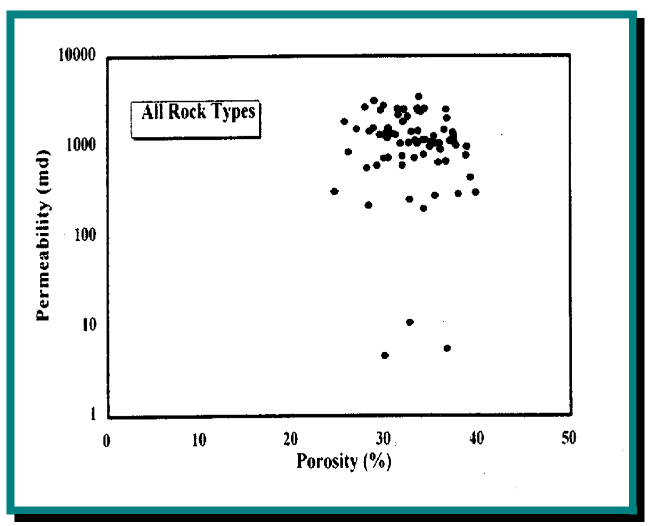


Figure 3.4.4-1 Core Analysis Data showing Porosity scatter region.

The procedure outlined above is cost effective as it requires no new evaluation wells, specified logs and well shut-ins. Field evaluation utilizing the Rock-Log model rely on existing data. This allows the economic and rapid implementation of the Rock-Log model.

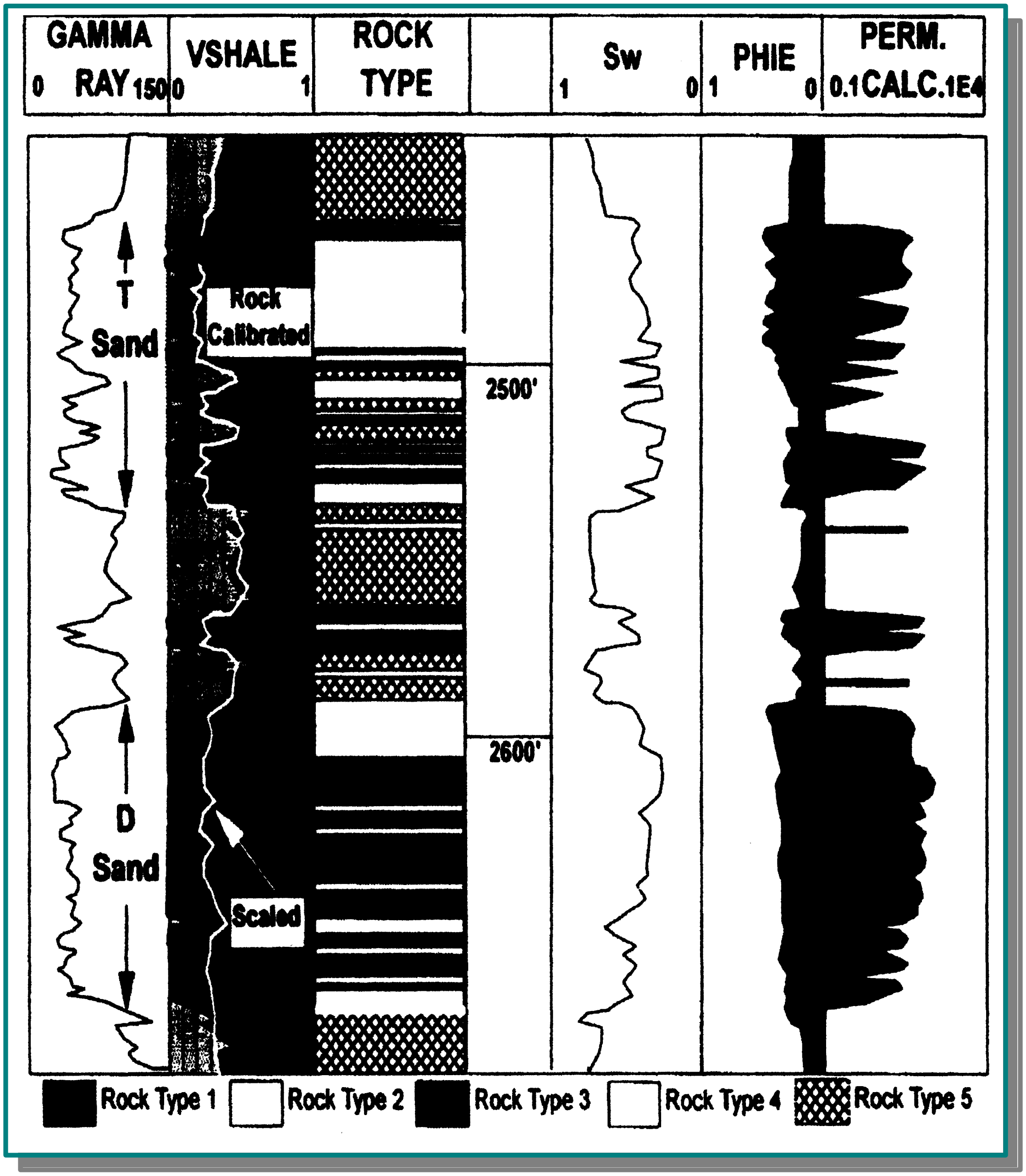


Figure 3.4.4-2 **Characteristic Log Response Profiles, Well UP901B**

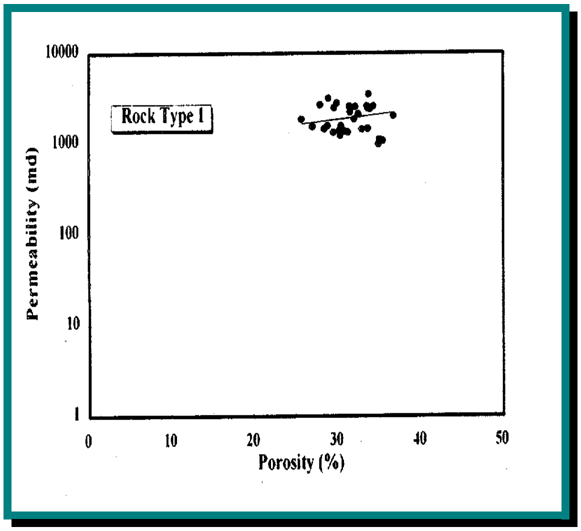


Figure 3.4.4-3a Permeability/Porosity relation for Rock Type 1.

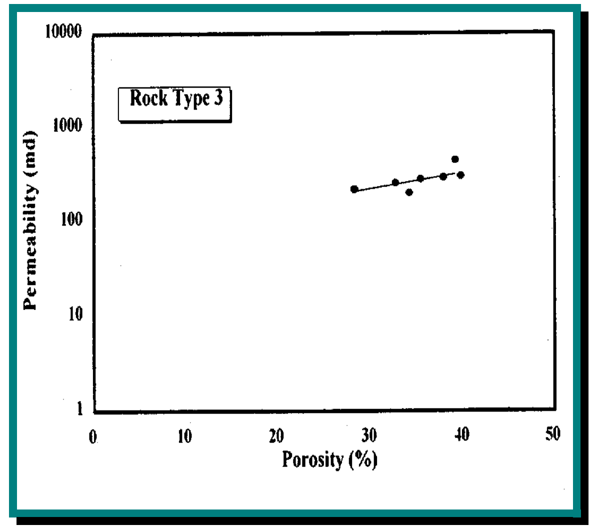


Figure 3.4.4-3c Porosity/Permeability relation for Rock Type 3.

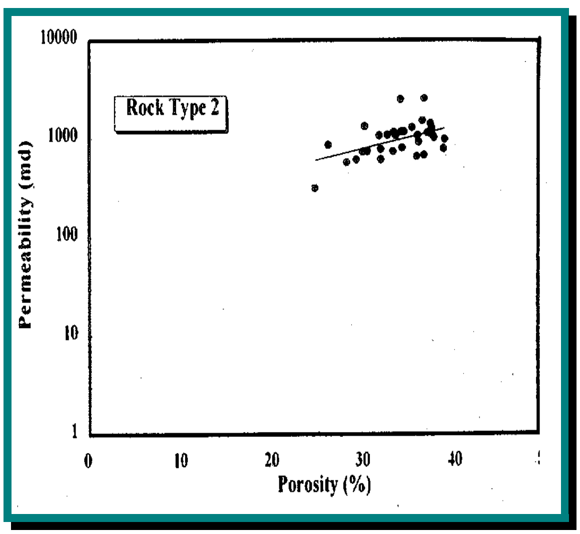


Figure 3.4.4-3b Permeability/Porosity relation for Rock Type 2.

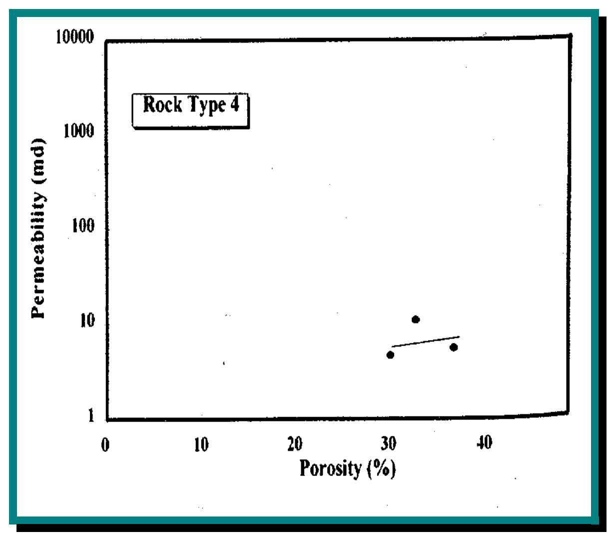


Figure 3.4.4-3d Porosity/Permeability relation for Rock Type 4.

3.4.5 3-D Deterministic Geologic Model

The completed 3-D deterministic model was derived from 18 horizons utilizing traditional reservoir characterization techniques. All the strata were successfully modeled, including the six normal faults, a paleochannel and onlapping sands. The deterministic model is required for the precise placement of horizontal wells within the heavy oil sands to facilitate gravity drainage via steam drive.

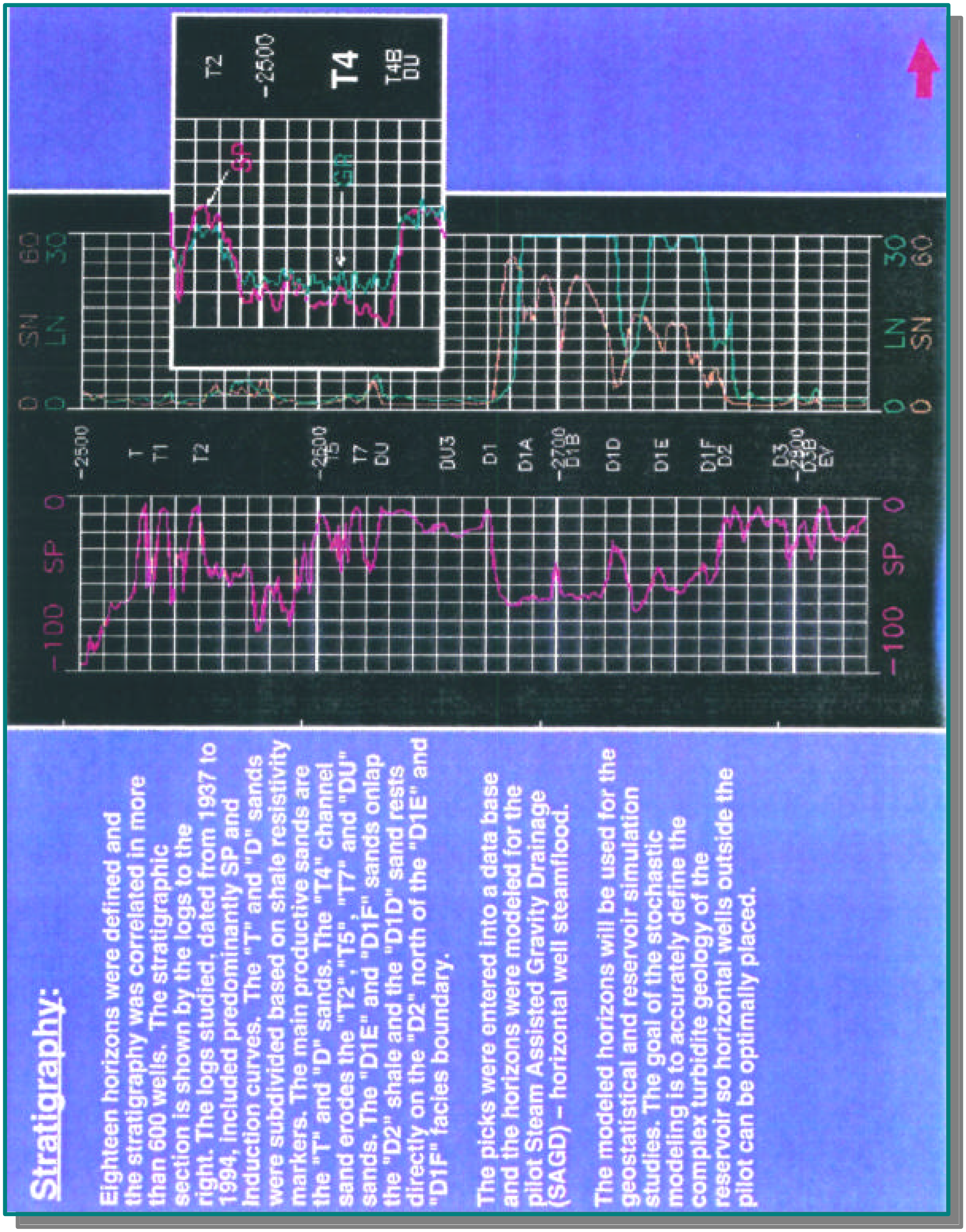


Figure 3.4.5-1 18 layers of the 3-Dimensional Geologic Model.

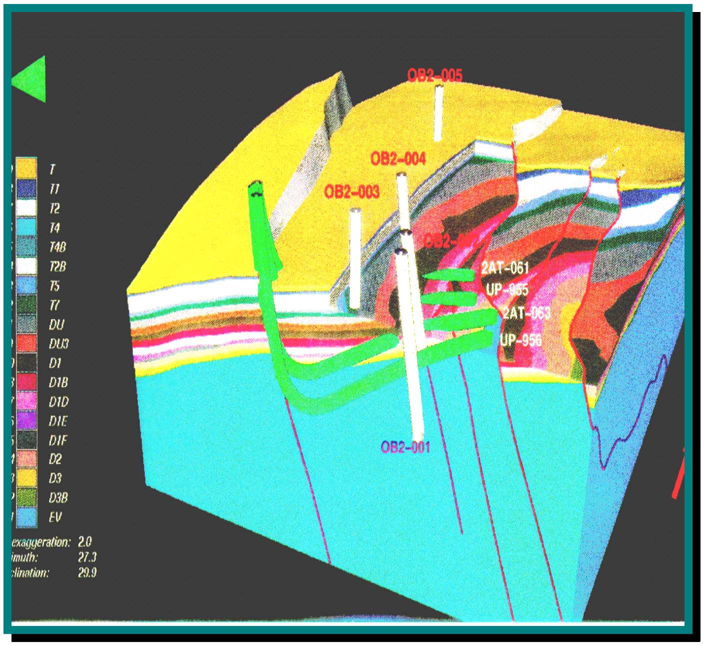


Figure 3.4.4-1 3-D view of horizontal and observation wells drilled in Fault Block II-A associated with the project.

The 3-D deterministic model developed was further used in the development of a 3-D visualization model which facilitates the development of graphical models with the integration of data such as velocity, hydrologic and property distribution in space. However, the bulk of associated work falls under Reservoir Simulation and shall be discussed in greater detail in the following chapter.

The 3-D Deterministic Geologic model was used to drill the 4 horizontal wells and five observation wells in Fault Block II-A. It was also the basis for the stochastic model and reservoir simulation.

A detailed discussion of the 3-D Deterministic Geologic Model was included in the previous annual report.

3.4.6 3-D Stochastic Modeling

The Stochastic Geologic model is expected to result in improved performance predictions over the current existing 3-D deterministic model. Flow simulations on layered reservoirs are often limited by the assumption of constant permeability (among other properties), which results in history matching and projected production forecasts of questionable reliability. Stochastic modeling allows for various realizations of the geologic framework and associated petrophysical properties to be incorporated into geologic and simulation models.

The stochastic model involves data integration of the conceptual geological model, sediment modeling analysis, Seismic data, well logs and core data as well as data made available through basic reservoir modeling.

3.5 Conclusions

3.5.1 Reservoir Engineering

An analysis of the production data for the Tar zone FB II-A was carried out to determine evidence of water influx in Fault Block II-A. An analysis of the bubble map representation of the cumulative water production prior to the onset of water injection displayed significant evidence of water influx in the southern end of FB II-A. There is also significant water production from a few wells, which are indicative of water influx from the northern end as well.

In determining Original Oil-in-Place (OOIP) from gas saturations, the cumulative gas produced was used. This methodology yielded 97MMstb of OOIP. The volumetric method was also utilized. This entails estimating the average hydrocarbon thickness and a constant porosity. The volumetric method yielded 92.5 MMstb of OOIP.

In an analysis of the primary and waterflood recoveries the total amount of liquid and gas produced from the Tar zone FB II-A was 18.5MMbbl liquid and 7.16MMMscf gas. It is assumed that the reservoir is not fully under water drive mechanism since reservoir pressure declined from 1100psi to 265psi..

The permeability of the various zones in FB II-A can be estimated by an extension of the x-plot technique, which proposes a linear relation between the fraction water cut and recovery. The water saturation in the Tar zone prior to the start of waterflooding are: 23% in the center; 26% in the south-east; 31% in central north, and 33% in the south of FB II-A. The time averaged water saturation in the central part of the field was not much different than the initial water saturation at 21%. An increase in 12% and 8% in the southern and central northern parts respectively was observed as a result of natural water influx.

In a comparison of water injection profile surveys to injection volumes in sub-zones, an analysis was made on the four producers surrounding the 2ATR-001 water injector. All producers experienced 5 successive breakthroughs. This is indicative that the reservoir possesses five layers with homogeneous properties. Correspondingly, a 5-year production history of producer MF-021 was carried out. A total of 20 successive breakthroughs for 4 injectors were observed. (See Figure 3.5.1) As the layers increase proportionally with additional injectors, this is consistent with our previous findings of 5 equivalent homogeneous layers.

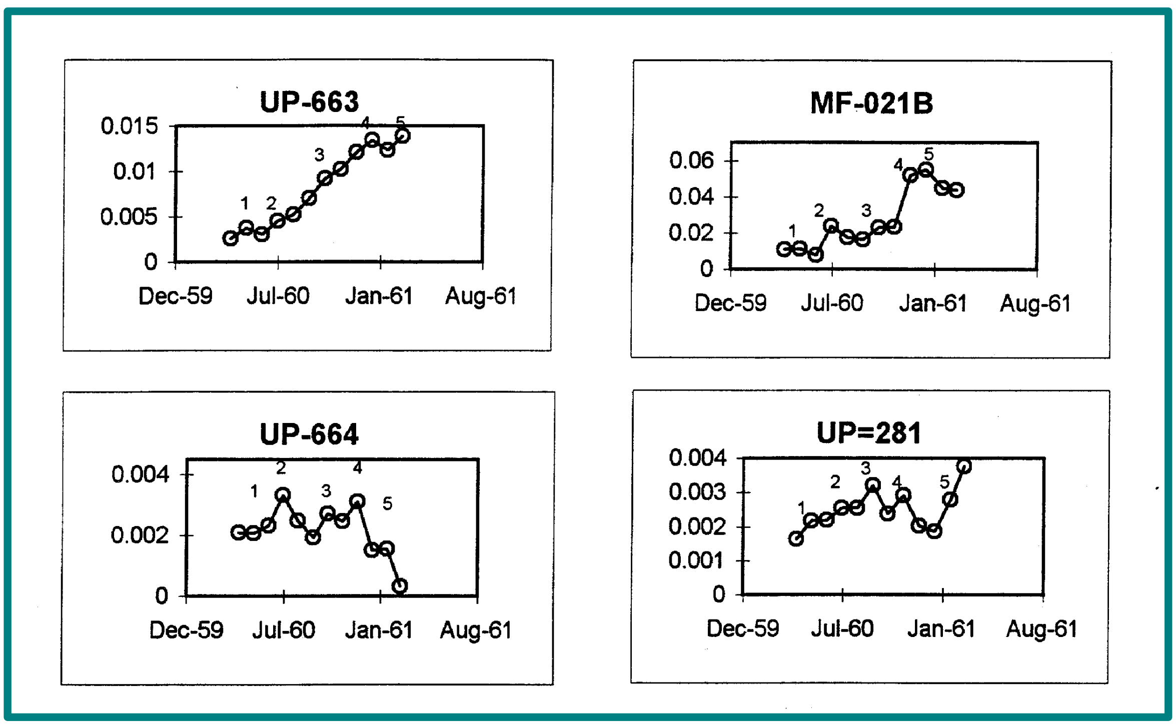


Figure 3.5.1 Cumulative-derivative plots of 4 different injectors showing five successive significant breakthroughs.

Past well cores obtained from the Tar zone of Fault Block II-A were evaluated for their suitability in the derivation of the rock-log model.

Calculating initial OOIP using the "cumulative gas produced" method provides a reasonable estimate that can be compared to the material balance method . An evaluation of the aquifer concluded that natural water influx is a significant drive mechanism in the Tar zone of FB II-A.

3.5.2 Geologic Models

The 3-D deterministic geologic model was further used in the development of a 3-D stochastic model, which facilitates the development of graphical models with the integration of data such as velocity, hydrologic and property distribution in space.

Work on the stochastic model has been in progress and is expected to be completed by the following reporting period. A sand sequence analysis, work on updating the neural network analyzer and reservoir tracer work is expected to form the database for which the stochastic model will emerge.

3.5.3 Petrophysical Models

We have made substantial progress on the Rock-Log model. The Rock-Log model provides a correlation for flow characteristics by identifying various rock-types based on their pore geometry as previously detailed. The method described affords a quick estimate of porosity to permeability ratio specific to each rock type. The method does not require new evaluation wells, specified logs and well shut-ins.

4. RESERVOIR SIMULATIONS

4.1 Introduction

The building of the 3-D deterministic geologic model was accomplished during the previous reporting period. The focus was characterization of the reservoir stratification, fault patterns and the scrutiny of a channel sand cutting through the upper part of the T sand.

This model served as the basis for the development of the 3-D deterministic reservoir simulation model. We have made substantial progress during the current reporting period.

4.2 Deterministic Geologic Modeling

Although the deterministic model has been completed, it is in the process of being scrutinized and modified as deemed necessary when more information is gleaned from information concerning Rock Types. Data integrated in the deterministic model is obtained from wells, logs and geographical surveys.

The data and models were viewed and manipulated interactively using workstations. The result of this work was the generation of a 3-D visualization model. The software is capable of developing and integrating the following types of representational models from scattered data point surfaces such as: terrain, velocity, hydrologic and property distribution in space, such as: permeability, porosity and temperature. The software is capable of generating various graphic representations of spatial data and models, including structure contour maps, isopach maps, cross sections, and 3-D shaded volume models. These representations can be converted to grid blocks for use in a reservoir simulation model.

4.3 STARS™ Thermal Reservoir Simulation Program

The STARS™ thermal reservoir simulation program by the Computer Modelling Group (CMG) of Calgary was selected as the software to be used for both the deterministic and stochastic modeling on the 2nd Quarter of the reporting period. The program will be run on the R10,000 Onyx RE2 workstation by Silicon Graphics Incorporated (SGI). Benchmark tests were performed by the project team, CMG and SGI. These tests successfully confirmed the capabilities of the integration of both software and hardware platforms. Thus, purchase and installation of the simulation software and computer hardware was completed in September 1996.

Deterministic Modeling commenced in October 1996, with the application of the CMG IMEX™ black oil simulator program and STARS™ for history matching. However, as detailed in the following sub-section, additional variables came into play, which needed to be taken into consideration.

4.3.1 Rock Compaction Algorithm

Two dynamic processes that affect the reservoir history matches require further study; plastic deformation of the rock and gas liberation. The project team developed an algorithm, which is capable of taking into account the local and dynamic features of rock compaction and rebound with respect to reservoir pressure. The project team and CMG incorporated the algorithm, called COMPACT into an alpha version (97.20) of STARS 97.00.[A25] This version is undergoing testing at the termination of the reporting period and is expected to be incorporated in its entirety during the next reporting period. In the interest of time, the dead oil feature of STARS is being applied in the simulation and the current configuration appears to exhibit stability.

4.4 Deterministic Reservoir Modeling

The 3-D deterministic reservoir simulation modeling of the Fault Block II-A Tar Zone will be performed on the STARS^{TM} thermal-compositional reservoir simulator from the Computer Modelling Group (CMG) of Calgary, Canada. The 3-D deterministic geologic model was used as the geological framework for the 3-D deterministic reservoir simulation model.

The simulation model incorporates the basic reservoir studies presented earlier and includes considerations with respect to the presence of aquifers, field obtained water/oil performance data and pressure histories.

The Tar Zone in Fault Block II-A was divided into four sub-zones in the upper sand "T" and two subzones in the lower sand "D". Current assumptions are that the "T" and "D" intervals and their subszones are not in hydraulic communication except through the wellbores. Figure 4.4-1 shows the simulation grid block model employed for history matching purposes.

A major problem in simulating of Fault Block II-A is in allocating of the production data among commingled intervals. There are three distinct time periods in the history of Fault Block II-A: a primary period (1937-1960), a waterflood pressure maintenance period (1960-1982) and finally a thermal recovery stage. While the primary and the pressure maintenance by water injections were treating the reservoir as one body, it was necessary to allocate back production to individual sands for later modeling of the thermal recovery phase.

Basic reservoir performance data for the Fault Block II-A Tar Zone was compiled and is shown in Figure 4.4-2. PVT data obtained from correlation studies are shown in Figure 4.4-3. The primary production phase was successfully matched using the Black Oil option of the CMG STARS^{TM}. Based on the relatively insignificant free gas production, the application of the single-phase hydrocarbon dead oil model was used to reduce run times.

During the history match of the primary production, the two mechanisms of compaction drive and water influx were considered. Significant sensitivities to the assumed values for rock compressibility were noted. Figure 4.4-4 shows the influence of assumed compressibilities. As shown in Figure 4.4-5, the late-time linear relation between cumulative production and average reservoir pressure indicated changes reflecting aquifer support as well as non-linear compaction effects. An improved algorithm was developed to incorporate compaction effects into the simulator.

4.4.1 Simulation Model Set-up

The Tar zone in Fault Block II-A is about 2300-ft deep at the reservoir top. The reservoir has an anticlinal structure with the structure top in the central-eastern location of the fault block. The Tar Zone in this fault block produces from the "T" sand and "D" sand. The "T" sand includes the T1, T2, T5 and T7 subzones and the "D" sand includes the D1 and D3 subzones. The "T" and "D" sands do not communicate with each other due to the shale barrier between them, and they only commingle through the wellbore. However, the T2, T5 and T7 subzones communicate with each other in certain locations due to the incision of a paleochannel and weak shale barrier among them.

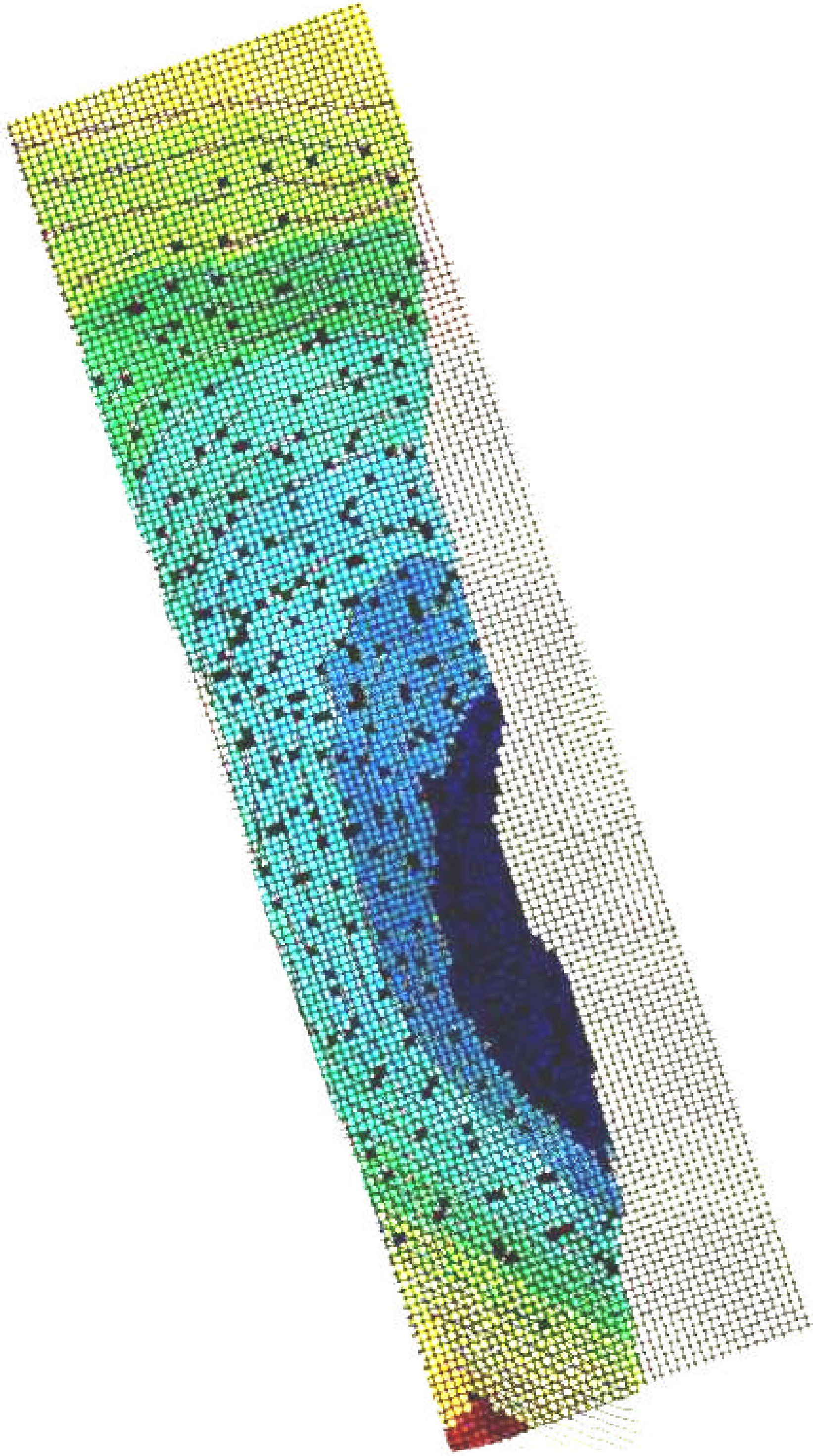


Figure 4.4-1 Setup of Simulation Grid Block.

The reservoir was initially in hydrostatic equilibrium and the initial pressure used was calculated based on hydrostatic conditions. The reservoir has separate aquifers for the “T” and “D” sands and the oil zone in the “T” sand covers a smaller area than that in “D” sand.

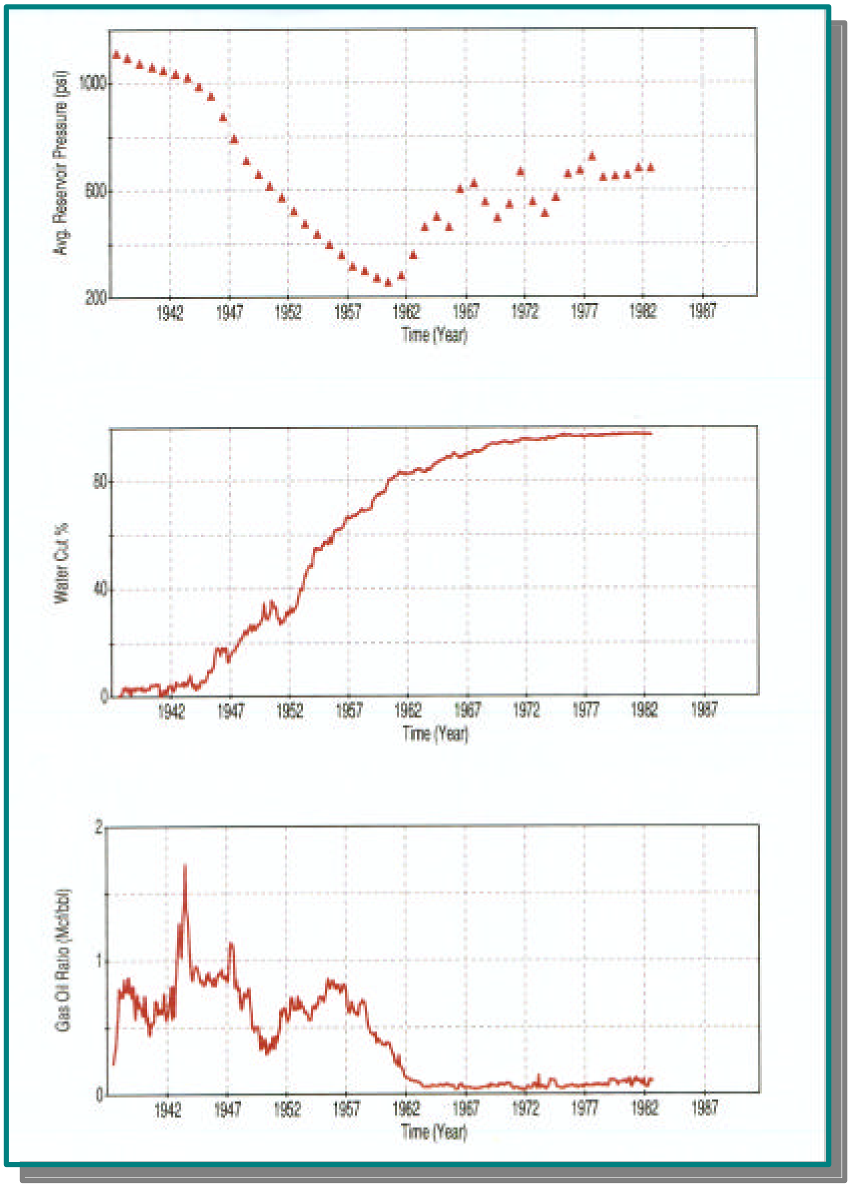


Figure 4.4-2 Field measured reservoir pressure, water cut and gas-oil ratio

Because the “T” and “D” zones are commingled in the primary and the waterflood wells, it is difficult and inappropriate to separate the “T” and “D” zones during the primary depletion and waterflooding phases in the simulation. As a result, all the zones were simulated together and the model was large. This combination of multizones prevented the simulation in high grid resolution due to the limiting computational power. For the steamflooding stage, however, steam injection was separated for the “T” and “D” zones and production was still commingled for the “T” and “D” zones. The total production rate was allocated into the “T” and “D” sands based on oil fingerprint information. This provided the possibility of separating “T” and “D” sands into separate simulation models and improving the accuracy of the simulation.

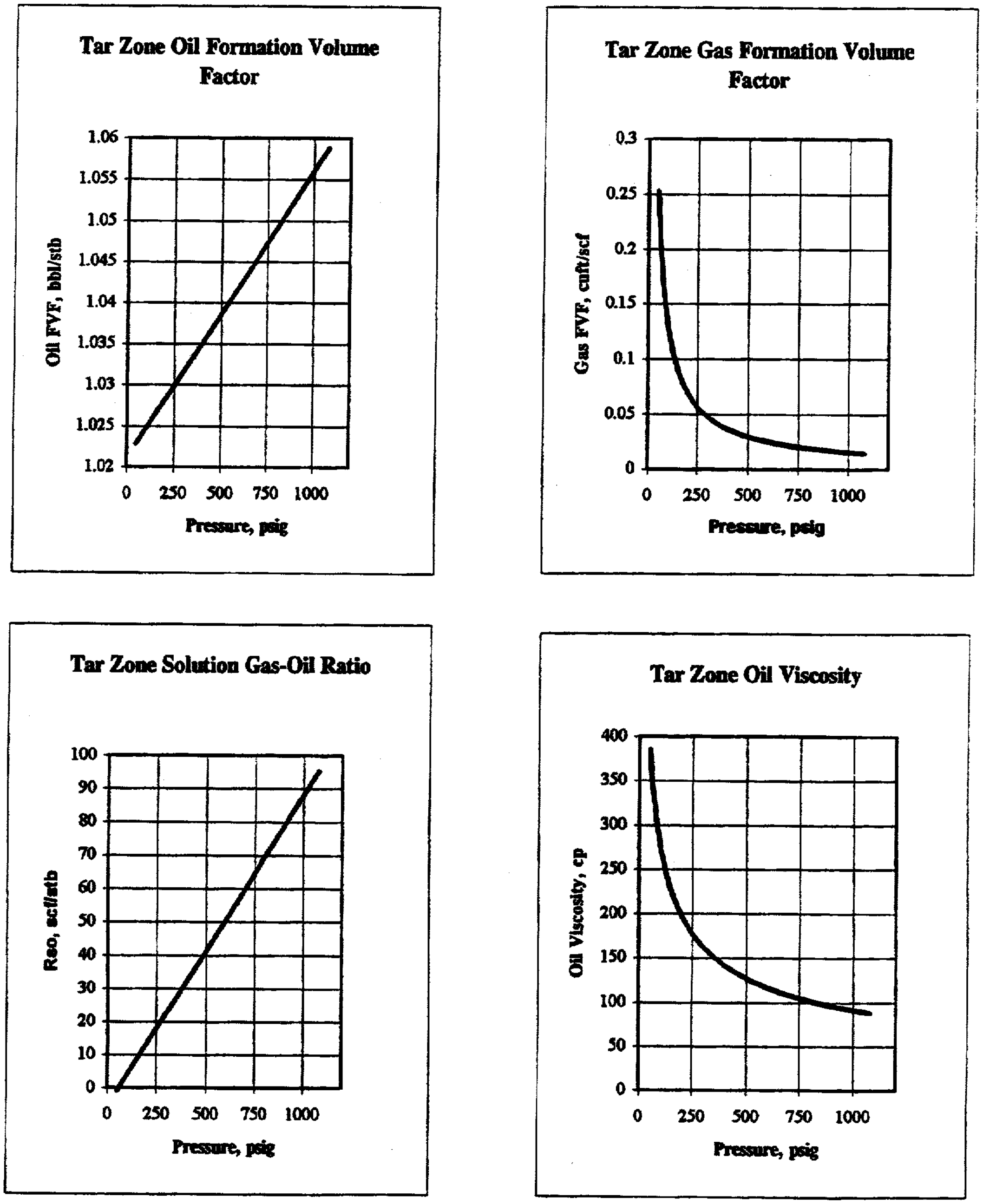


Figure 4.4-3 Fluid Properties for Tar Zone in Fault Block II-A

One of the objectives of the history match for the primary depletion and waterflooding process was to estimate the reservoir conditions in the individual subzones. After the simulation for primary depletion and waterflooding, the ”T” and “D” sands were split into separate models in order to improve the simulation accuracy, which is required to describe certain phenomena for steam operations such as steam override, steam assisted gravity drainage (SAGD) and so on.

On the areal plain, the whole area was simulated together for the primary depletion stage due to the influence of aquifers from both the north and south flanks. Therefore, a full field simulation was more appropriate although it is computationally more intensive and time consuming. Four grid blocks were used in the vertical direction in the deterministic simulation. These four grid blocks corresponded to the four formation layers of the T1, T2 through T7, D1 and D3 subzones. The net thickness of these four layers are calculated by using the total thickness and an average net/gross ratio. It is obvious that the layers T2-T7 and D1 are much thicker than the rest of the layers and are the major producing contributors.

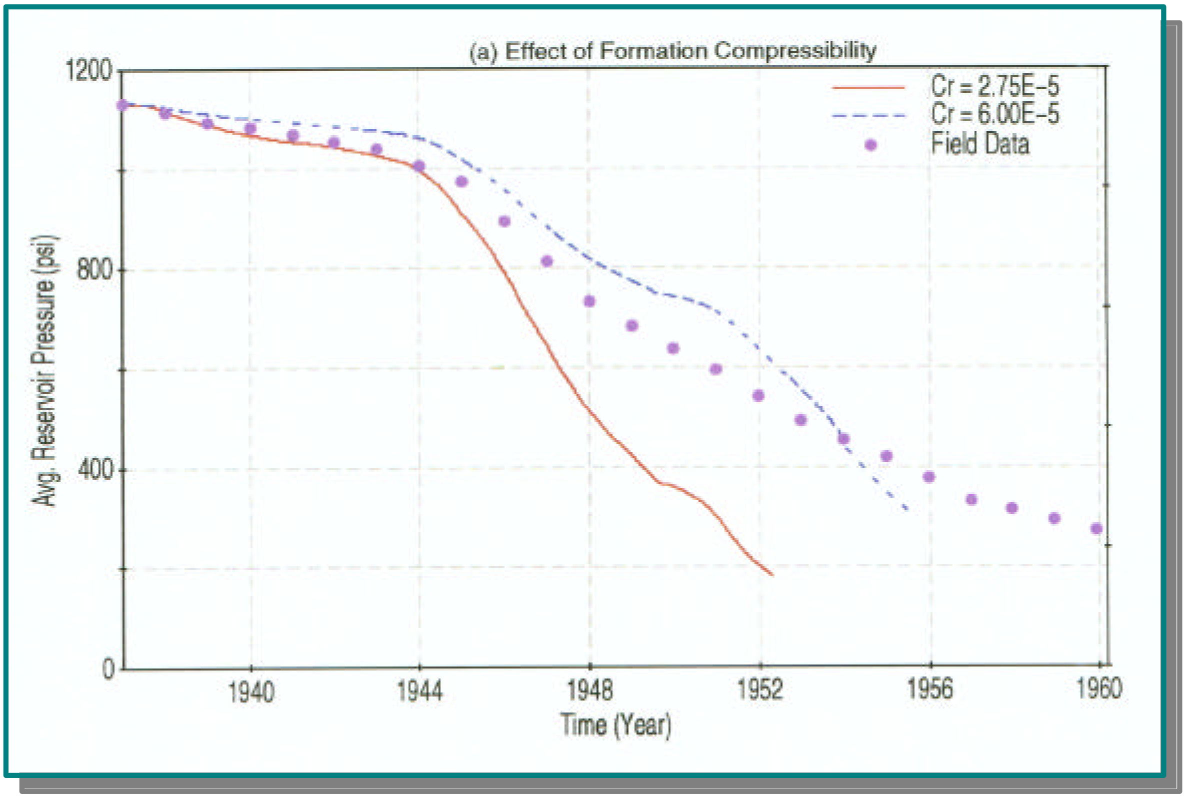


Figure 4.4-4 Effect of Formation Compressibility on Production Performance

The production history data for this reservoir can be found from the Production Analyst database. Figure 4.4-2 shows the field-measured average reservoir pressure, water cut and gas-oil ratio. The reservoir underwent primary depletion between 1937 and 1960, and experienced waterflooding between 1960 and 1982. The water cut is lower in the initial several years, and it increases dramatically due to the contribution of aquifer water invasion and remains high in the waterflooding stage. The gas-oil ratio was about 250scf/bbl for the first several months, which can be considered as the initial solution gas-oil ratio. The gas-oil ratio was reduced to 100scf/bbl during the waterflooding stage. Figure 4.4-3 shows the PVT data applied to the simulation study.

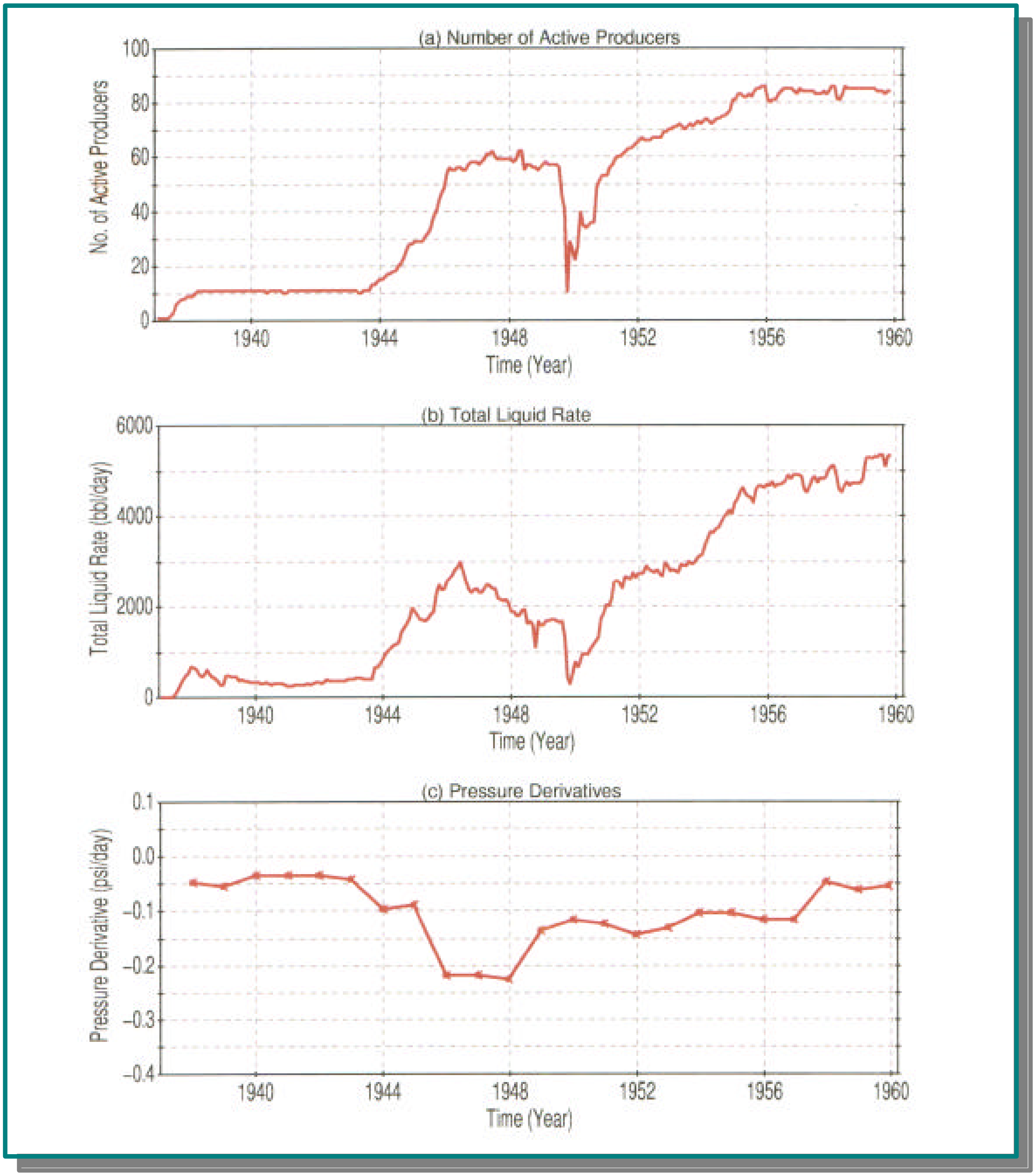


Figure 4.4-5 Analyzing Field Production Performance

In the primary depletion stage, the reservoir was simulated by inputting the oil production data measured in the field and allowing the model to predict the pressure and water production. In the waterflooding stage, however, the reservoir was simulated by controlling constant bottom-hole pressure and predicting the fluid productions. This kind of controlling strategy should be more representative of the field reality.

Permeability and porosity applied in the simulation was estimated from well logging analysis, which are 1000md and 29% respectively. They may be adjusted in the history match. Relative permeability data will be determined by history matching the pressure and water-oil ratio histories.

Figure 4.4-1 shows the simulation grid blocks for this reservoir for the deterministic simulation study, which is 43x157x4. The aquifer was attached to the last grid blocks in the north and the south flanks. The simulation coordinates adopted are different from the geological coordinates in order to reduce the ineffective grid and computational requirements by aligning the simulation coordinates approximately parallel to the Wilmington Fault and the steam pilot well patterns. Different aquifer sizes were simulated by adjusting the sizes of the last grid blocks in the north and south flanks.

The first decision made was to utilize the dead oil feature of the simulator, rather than the compositional feature. The historic gas production rates were basically proportional to oil production for most of the primary depletion process, which implies that there was no significant free gas saturation in the formation. This phenomenon validated the use of a single-phase dead oil model. Therefore, the contribution of a compositional effect was not significant, at least for the primary depletion and waterflooding stages. The compositional model will still be used for steamflooding, if necessary. For the primary depletion and waterflooding phases the dead oil feature of CMG STARS™ simulator was used because it is more time efficient and stable than the compositional feature. The equivalent viscosity of the dead oil will be adjusted by Standing's correlations which took into consideration the contribution of dissolved gas in reducing dead oil viscosity.

4.5 3-D Stochastic Modeling

4.5.1 Introduction

At present, the stochastic model is still in the process of being developed for effective use in modeling the Fault Block II-A Tar Zone. The long-term objective is to extend its usage throughout the field. The application of such technology should reduce reservoir risk by narrowing the range of error associated with the reservoir parameters.

At the termination of the reporting period, the stochastic geologic model has not been developed and therefore, has had no role in reservoir simulation.

4.5.2 Stochastic Modeling Setup

The inefficiency of steamflooding in the Fault Block II-A Tar Zone can be attributed to the improper utilization of injected heat. Heat losses and bypassing of oil-saturated intervals accounted for unusually high steam-oil ratios observed in the area.

One of the essential purposes of stochastic modeling is delineation of the factors that control vertical permeability and lateral continuity of the shale breaks. Superposition of information derived from well logs and cores to the already constructed bulk representation of geological framework of the reservoir can lead to development of probabilistic images for fluid flow and heat flow modeling. The basic ingredients for building stochastic images of the reservoir are the well logs and core-derived properties. Progress was made in quality checking the well log data.

A total of 178 well logs have been digitized, environmentally corrected and normalized. Among these, 78 wells have porosity logs, which cover the middle-northern flank of Fault Block II-A.

Core materials are available for ten 1981-1988 vintage wells within the existing steam drivearea. Wells OB2-3 and OB2-5 were recently drilled and cored in 1995. The core materials from these wells are being preserved in a refrigerated storage while detailed plans for improving core analyses and calibrating old core analyses data are being developed. The objective is to perform modern correlation studies between core and log data.

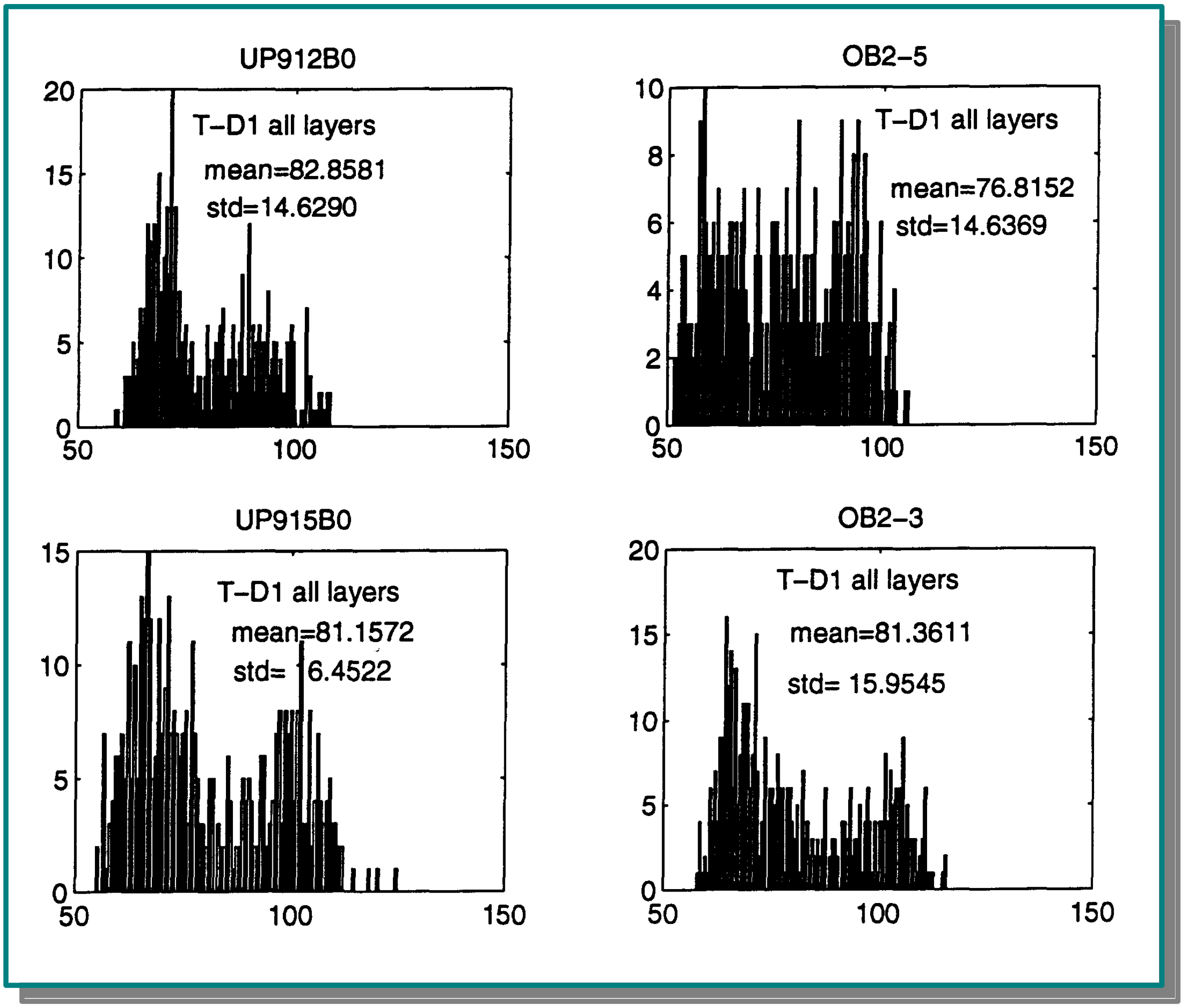


Figure 4.5.2 Gamma Ray (GR) Histogram Plots for Well UP912B, UP 915B and OB2-3, and OB2-5, "T" and "D1" section.

Recognizing the crucial dependence of any stochastic modeling work to having quality data, a considerable effort was made to conduct a quality control of the well log data. A number of well logs that were conventionally normalized has to be corrected. The methodology of normalization by the use of shifting mean values over multiple lithologies or over too large an area was questioned for this reservoir. Initial normalization work actually minimized the differences in log character between wells, thereby homogenizing the reservoir heterogeneity. Figure 4.5.1 shows typical histograms and the non-uniformity observed on four wells representing the northern, central and southern part of the fault block. Corrections were made that reflected local averages rather than global as used in the existing calibration. Specifically, the log data should be normalized according to the local statistical characteristic.

4.6 Neural Network Modeling

Lithological well log responses can be used in cross-hole correlation studies. In turbidite sequences, patterns observed on lithological logs can show considerable changes across the reservoir. Dividing log-derived lithology indicators into small intervals and establishing similarity of response requires massive amounts of 2-D and 3-D pattern recognition and correlation studies.

A study was conducted using neural network models to establish similarity of responses for lithological patterns observed on the well logs from the Fault Block II-A Tar Zone.[A24,C21] Log responses from the gamma-ray, spontaneous potential, and shallow resistivity tools were used as lithology indicators. Shallow resistivity was preferred to deep resistivity as it is more sensitive to lithology and less to hydrocarbon saturations.

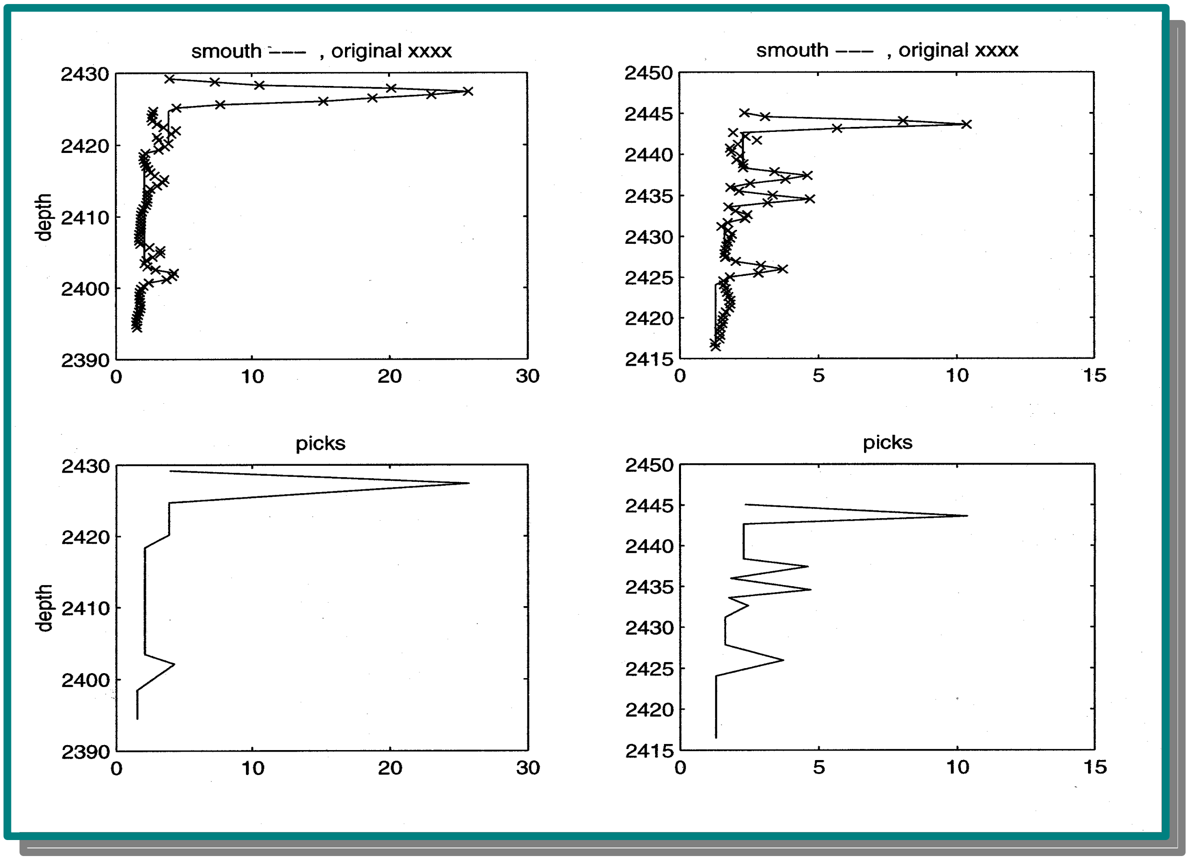


Figure 4.6-1 The two top figures demonstrate the smoothing process, while the two bottom figures are obtained from smoothed patterns identifying major picks.

A smoothing algorithm was developed to filter out noise from the lithology logs data. Patterns were then detected by the accounting of the repeated sequences of minima and maxima. Sub-groups representing various sequences were conceptualized and the pattern recognition approach was developed to include different patterns. Figure 4.6-1 shows examples of simplified input patterns.

The methodology of error back propagation was applied to the patterns. Figure 4.6-2 shows the result of the recall process after completion of the training process for a small interval of the Fault Block II-A Tar Zone.

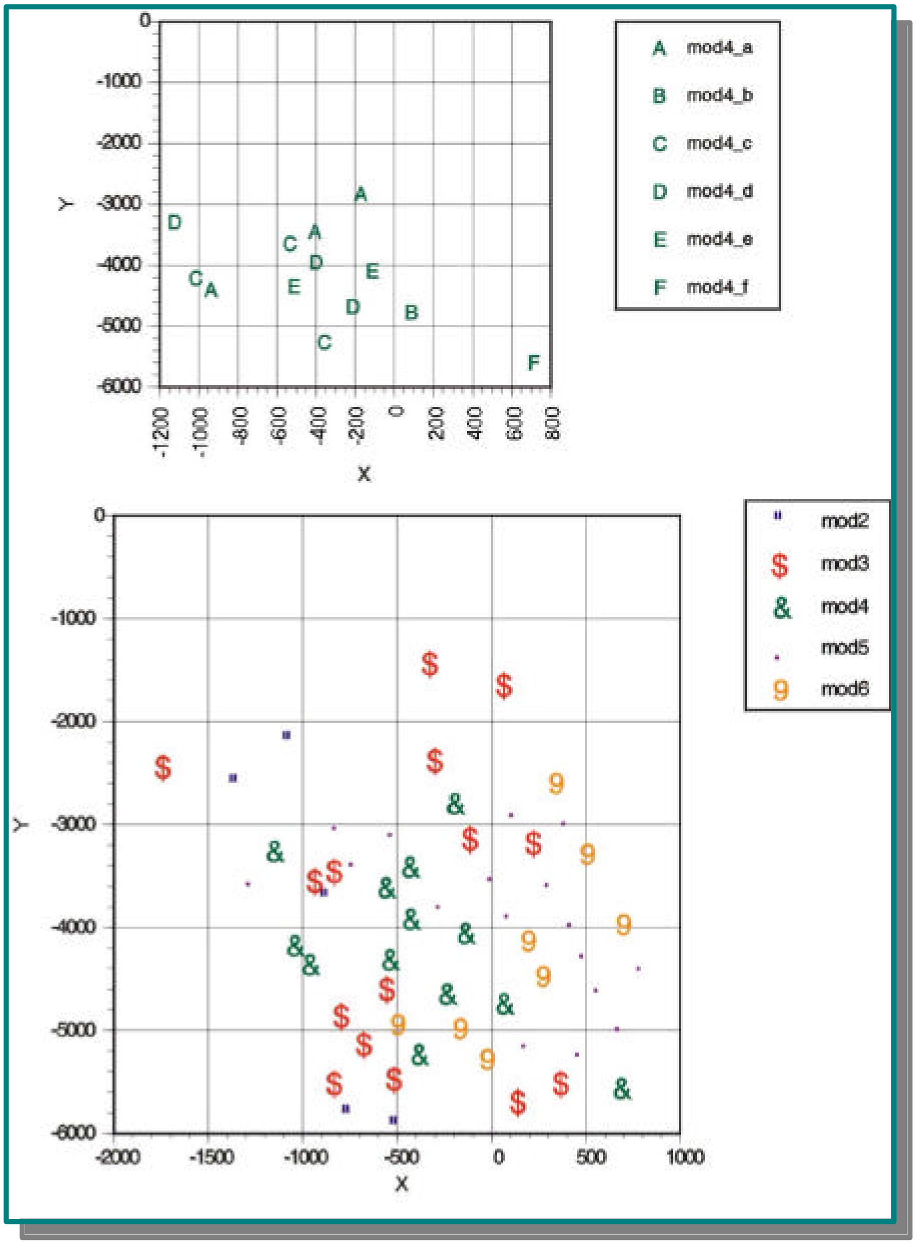


Figure 4.6-2 Two examples of lithological pattern classification that illustrates the existence of different zones.

A deficiency of these techniques is the non-uniqueness of the results. While input patterns comprised of more data points can improve the recognition process, the size of the Newark increases with more complexity in the training process. A data compression algorithm is being developed which will use linear transform to handle a large amount of sampling points while keeping the training process less complex.

To test the effectiveness of the transform approaches, synthetic data were generated using n-dimensional polynomials. The method of discrete sine transform (DST) is the most suitable for these types of signals as shown in Figure 4.6-3.

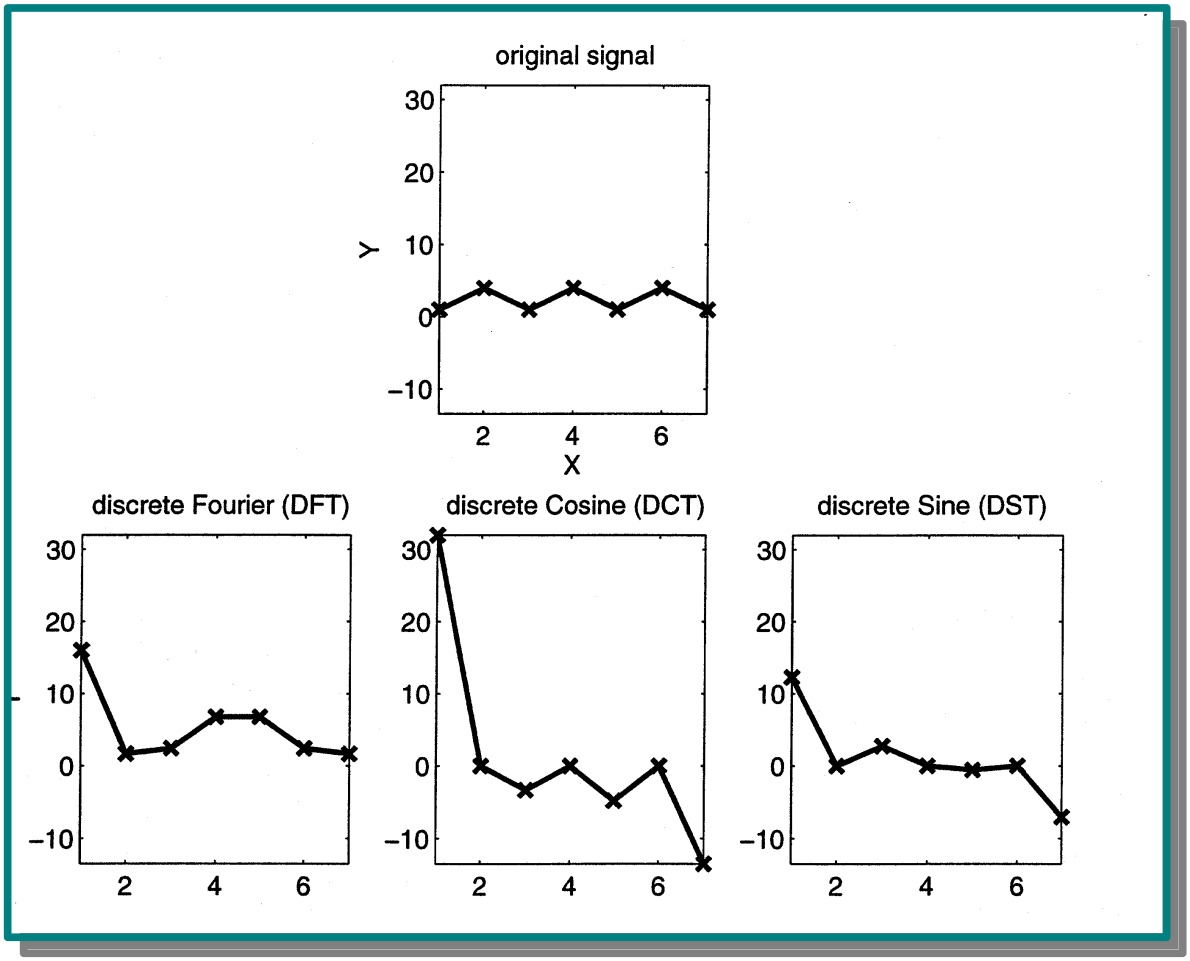


Figure 4.6-3 Comparison among different transforms, with the discrete Sine transform being the best.

Work is continuing on the application of the proposed methodology to the well log responses in Fault Block II-A.

4.7 Petrophysical Rock-Log Model

Modern well log and conventional core data from Fault Block II-A was instrumental in the development of the petrophysical Rock-Log model. Also essential for development of the model, was the establishment of distinct rock types which were empirically dependent on their flow characteristics, as defined by their porosity/permeability ratio.

It is expected that the Rock-Log model, as well as the porosity/permeability algorithm, will play a major role in the eventual derivation of the stochastic model.

5 RESERVOIR MANAGEMENT

5.1 Introduction

The thrust of the project, with reference to reservoir management, involves the implementation of a two-stage process. The first stage involves the development of advanced geologic and reservoir simulation models, and initiating pilot tests utilizing three different thermal recovery strategies to determine the most effective mode of recovery. The second phase involves the expansion of thermal recovery throughout the southern half of the Fault Block II-A Tar zone, based on the results of the pilot tests with guidance provided by the geologic and simulation models developed.

This reporting period saw the implementation of the following thermal recovery technologies:

1. Cyclic steam stimulation into four horizontal wells
2. Hot water alternating steam (WAS) drive in the four mature steamflood patterns
3. Continuous Steam Injection into four horizontal steamflood wells (2 producers, 2 injectors)

Also, due to the unconsolidated nature of the turbidite sands within the Wilmington Field, a novel sand consolidation completion technique using alkaline-steam injection was carried out to determine its effectiveness. Figure 5.1-1 shows the locations of the Fault Block II-A Tar Zone wells, including the four new horizontal wells. The wells were drilled and completed to thermally recover heavy oil using a pseudo steam-assisted gravity drainage (SAGD) technique.

In addition, new activity within Fault Block II-A required the procurement and installation of new facilities. Work done during this reporting period includes:

4. Application of improved caustic H_2S stripper
5. Installation of a 7ppm NOx 50MMBtu/hr oil field steam generator operating on low Btu waste gas.

The successful application of these preceding programs will weigh favorably on marginally profitable wells, by reducing the operating costs. Additional tasks related to evaluating production response include analyzing petrophysical and geochemical interactions, evaluating steamdrive mechanisms and monitoring the response of the reservoir.

5.2 Summary of work done the previous reporting period

Of the four horizontal wells drilled in late 1995, the two injection wells are 2AT-61 and 2AT-63, and the two producing wells are UP-955 and UP-956. The measured depths of these wells range from 4380-4820-ft with lateral sections in the target “D1” sands ranging from 1700-2075-ft long. True vertical depths range from 2410-2660 ft. All of the wells were completed over the last 600-ft of the horizontal section. The wells were drilled with an adaptation of the SAGD method as detailed by Butler.[D2,D4] However, as the oil-bearing zone of interest is of a relatively small vertical displacement, there is limited flexibility in implementing a textbook SAGD. Instead, a pseudo SAGD was implemented, which involves positioning the injectors and producers updip on structure to take advantage of the density difference between steam and the formation fluids and to focus the limited steam volumes over a smaller completion interval to create a steam chest. A more detailed description of the methodology involved in drilling a pseudo SAGD can be found in the previous year’s report. See Figure 5.5-1 for layout of wells.

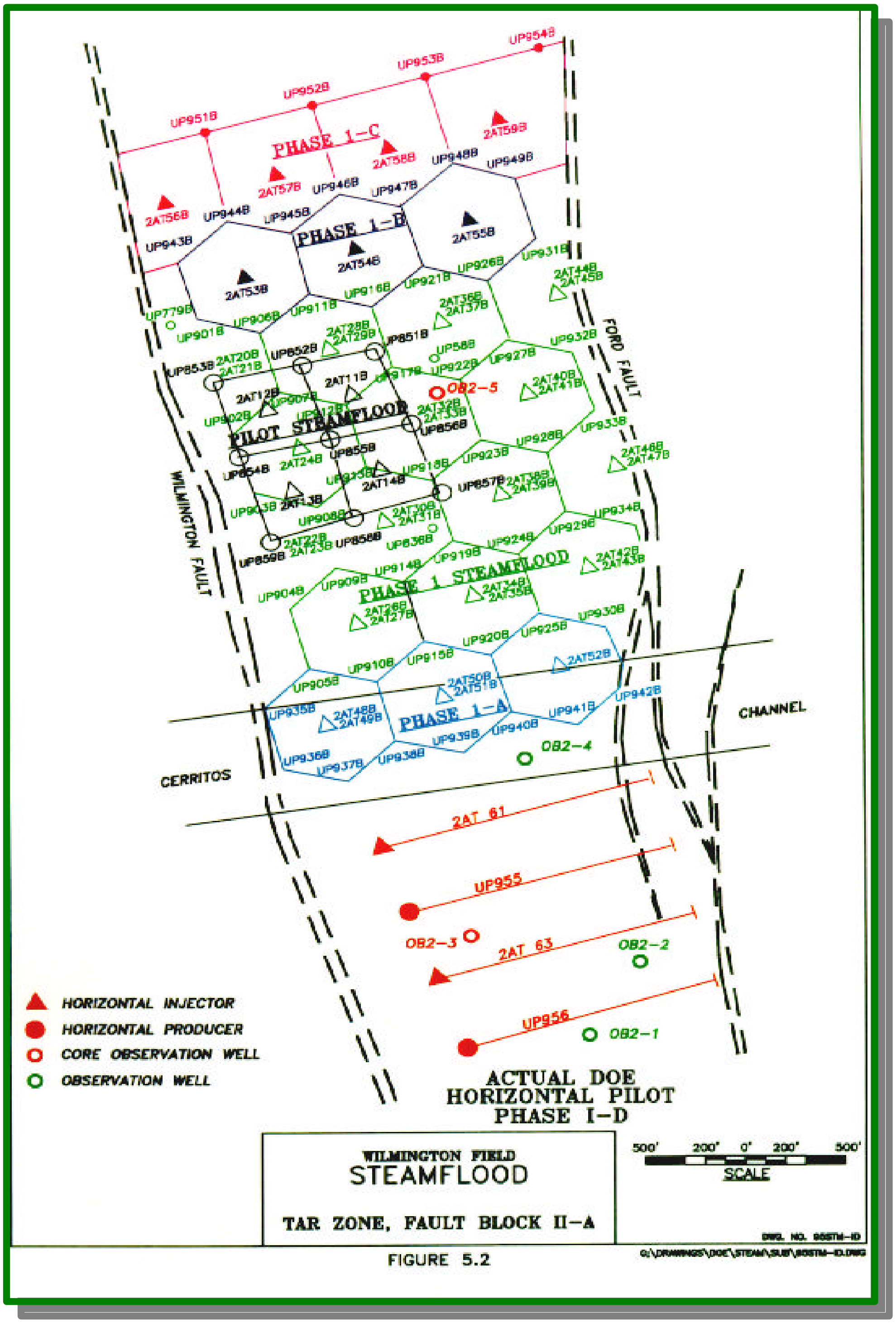


Figure 5.5-1 **Plan view of project wells, UP955, UP956, 2AT61 and 2AT63, within the Tar Zone, Fault Block II-A, Wilmington Field.**

To facilitate a steady supply of steam for these newly drilled injectors on Terminal Island, a 2100-ft steam transmission line was installed under a ship channel. The start-up of steam transmission commenced in December 1995, and the steam line channel crossing has had no operational problems to date. The installation of the steam line channel crossing and start-up of operation was detailed in the previous annual report.

5.3 Associated Work on Thermal Recovery Project

The two injection wells, 2AT-61 and 2AT-63, were selectively completed with 11 ¼-inch limited entry perforations per well. The two production wells, UP-955 and UP-956, were selectively completed with 48 and 36 ¼-inch perforations, respectively, to provide more productivity and test the perforating limits of the sand consolidation process. Cyclic steam injection was initiated in December 1995 and the four wells initially would accept only low rates of about 300 barrels of cold water equivalent steam per day (BCWESPD), at 1300 psi injection pressure and 900 psi reservoir pressure. Injection rates increased to the desired rate of 1500 BCWESPD per well over time, which was accelerated in a couple of cases by breaking down the perforations with high-pressure water.

5.4 Cyclic Steam Stimulation on Horizontal Wells

5.4.1 2AT-61 and 2AT-63

Injection wells 2AT-61 and 2AT-63 were given cyclic steam stimulation jobs of 146,000 and 186,000 bbls steam, respectively (corrected figures from previous quarterly report) during the first half of 1996 and began producing in early summer. Production results were mixed. Gross production rates ranged from 1200-1500 BPD/well compared to projected rates of 300 BPD/well. Peak oil production rates ranged from 41-60 BPD/well compared to projected rates of 300 BOPD/well. The low oil production rates cannot be explained at this time. Well 2AT-61 was converted to continuous injection in November and well 2AT-63 was converted to injection in January 1997 at rates ranging from 1700-2000 BCWESPD.

Refer to Figures 5.4.1-1 and 5.4.1-2 for graphical timelines of injection and production for 2AT-61 and 2AT-63 respectively.

5.4.2 UP-955 and UP-956

Production well UP-955 commenced cyclic steam injection in June 1996 and was given a cyclic steam stimulation job of 114,000 bbls steam. The well was placed on production in November and reached 1450 BPD gross and 80 BPD oil by the end of March 1997.

Production well UP-956 commenced cyclic steam injection in August 1996 and was given a cyclic steam stimulation job of 183,000 bbls steam. UP-956 was placed on production in January and reached 1570 BPD gross and 103 BPD oil by the end of March 1997.

The oil and gross rates were on the low side compared to projected rates of 2100 BPD gross and 300 BPD oil. At the end of the reporting period, UP-956 gross and oil production rates were increasing and UP-955 oil production was decreasing but gross rates were increasing. UP-955 should respond soon to steam drive injection from the two offsetting horizontal injectors as a means of possibly increasing oil production. Refer to Figures 5.4.2-1 and 5.4.2-2 for graphical timelines of injection and production for UP-955 and UP-956, respectively.

All four horizontal wells have reported no sand fill during well pulling operations, indicative of successful alkaline steam sand consolidation jobs on their perforated completions.

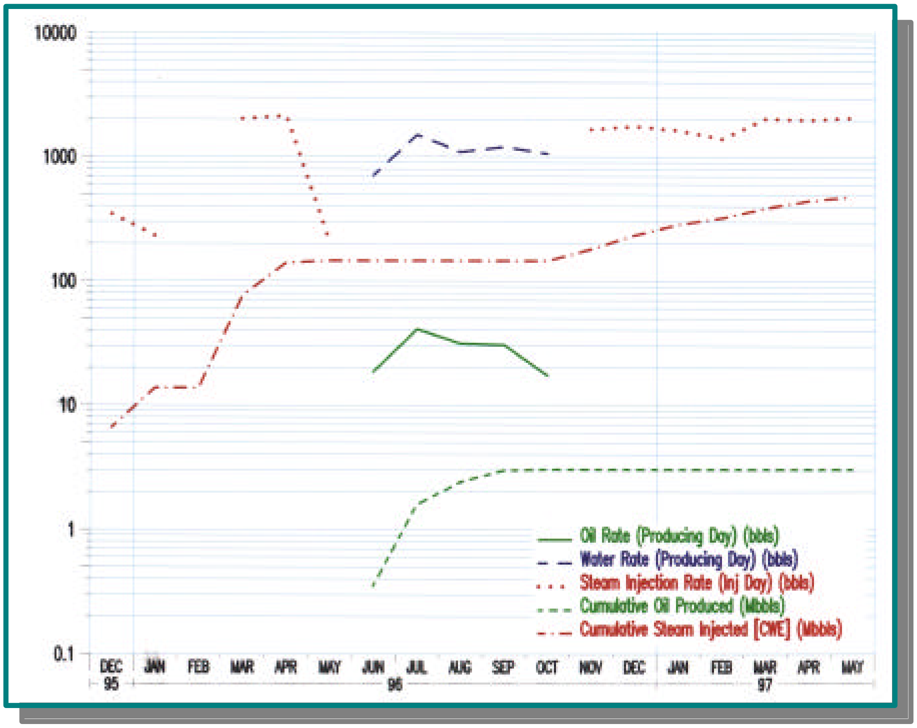


Figure 5.4.1-1 A graphical summary of two years of production history of 2AT-61

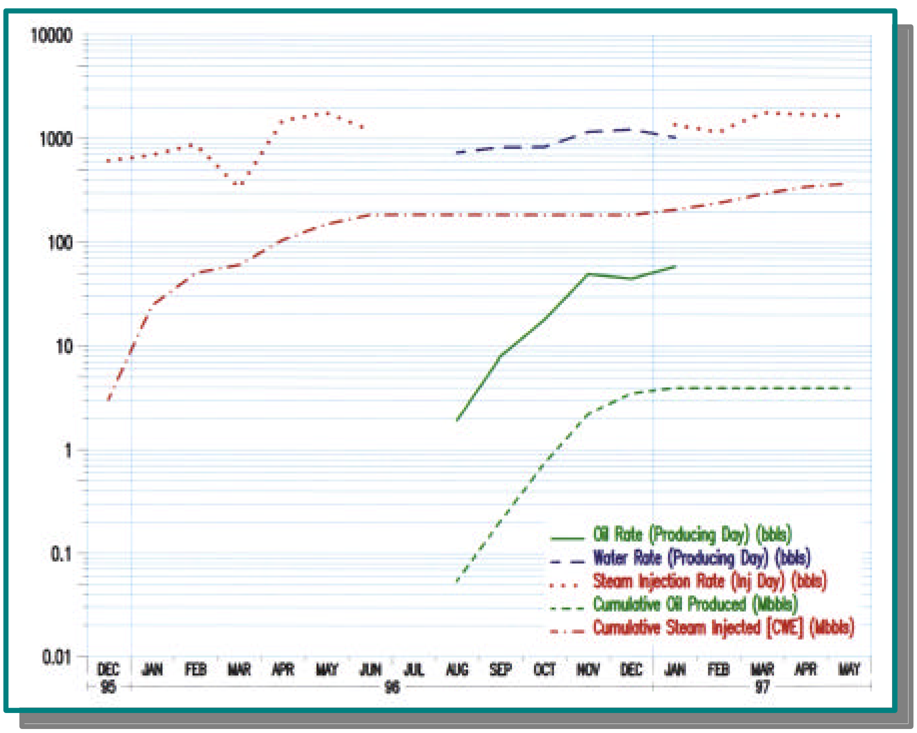


Figure 5.4.1-2 A graphical summary of two years of production history of 2AT-63

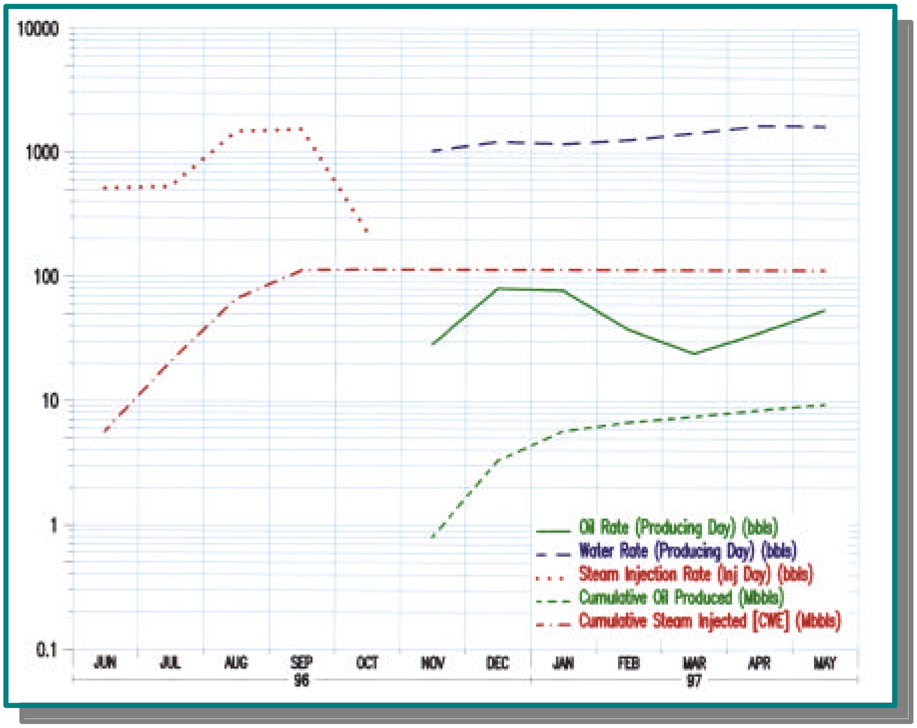


Figure 5.4.2-1 A graphical summary of two years of production history of UP955

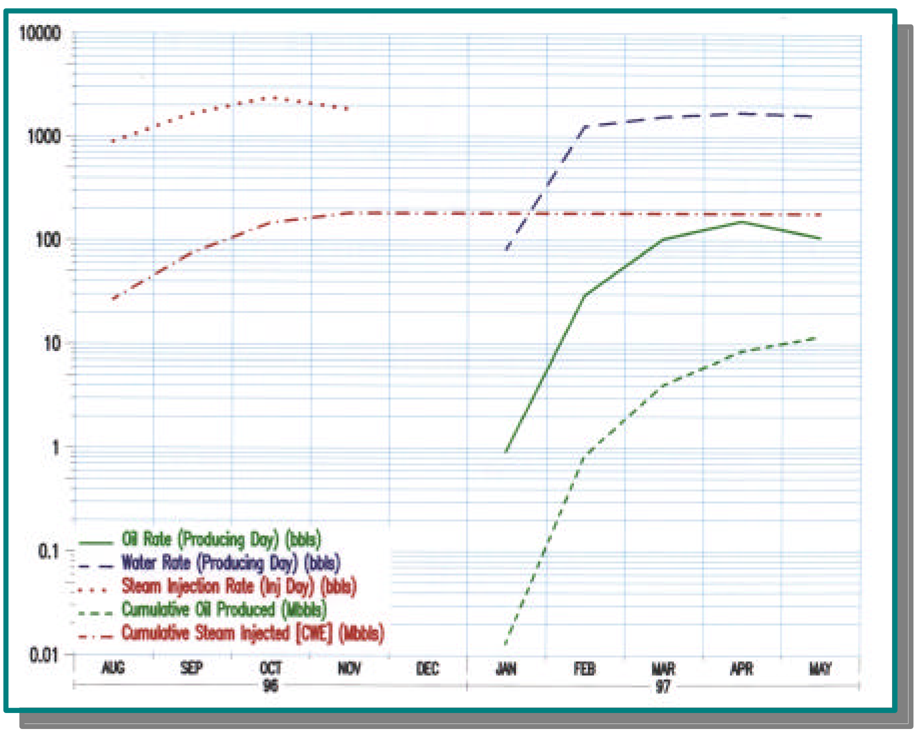


Figure 5.4.2-2 A graphical summary of two years of production history of UP956

5.5 Water Alternating Steam (WAS) Drive

Four existing vertical steam injection wells (2AT-32, 2AT-33, 2AT-40 and 2AT-41) were converted to hot water injection from March 1995 to February 1996. Hot water injection rates ranged from 500-3000 BWPD during this period. Hot water injection was temporarily suspended and steam injection was resumed from February to November 1996. This was due to surface owner requirements which necessitated moving the hot water injection lines. Hot water injection resumed in November at 4400 BWPD. No adverse or beneficial production response has been observed to date.

One major difficulty in observing response to hot water injection is scale buildup in the producers which reduces productivity until the wells are acidized. Four additional steam injectors (2AT-36, 2AT-37, 2AT-44 and 2AT-45) were converted to hot waterflood injection in February 1997. Reservoir tracers were injected into wells 2AT-32 ("T" sand) and 2AT-33 ("D" sand) on February 14 1997. This is described in section 3.3.2 of this report.

5.6 Continuous Steam Injection

Injection wells 2AT-61 and 2AT-63 were converted to continuous steam injection in November 1996 and January 1997 respectively. Injection rates ranged from 1700-2000 BCWESPD (Barrels Cold Water Equivalent Steam Per Day). These rates can be seen in Figures 5.4.1-1 and 5.4.1-2.

There is insufficient information to attribute any effects of continuous injection on UP-955 and UP-956. At the end of the reporting period, it was noted in section 5.4 (Cyclic Steam Stimulation on Horizontal Wells) that UP-956 gross and oil production was increasing, however, UP-955 gross was increasing but net oil was decreasing. More conclusive data will be obtained and discussed in the following reporting period.

5.7 Application of a new Low Cost H_2S Caustic Scrubber

5.7.1 Introduction

The application of caustic for sulfur (as H_2S and mercaptans) removal from gas streams is atypical, given the possibility of CO_2, which will react with caustic and consequently affect the absorption of H_2S. However, it has been shown that caustic scrubbing can be applied to streams containing up to 85% CO_2 if accompanied by a marginal increase in the residence time. [A18,B5,C18]

Gas to be treated comes from two streams. The first being natural gas produced from waterflood, and the second being natural gas from steamflood. The resultant gas to be treated has 40% CO_2, 8,000 ppm H_2S, and 300 ppm Mercaptans with a daily flow rate of 2.0 MASCO.

The original four-stage caustic scrubber was designed and initially operated by Union Pacific Resources Company. While efficient, the process entailed a high expense for removing lower concentrations of sulfur from the gas stream. The Sulfatreat™ process, however, was known to achieve high efficiency in the removal of smaller concentrations of H_2S from the gas stream, but not with higher H_2S concentrations. In addition,

A collaboration of engineers from T.J. Cross Engineers and Tidelands Oil Production devised a hybrid design, which incorporates the bulk sulfur removal efficiency of caustic and a more cost-effective trace amount removal scheme, using the Sulfatreat™ process. The resultant scrubber process is being marketed as Lo-Cost℠.

5.7.2 Chemical Interactions

H_2S is soluble in the caustic solution and a corresponding equilibrium is set up between the free H_2S, the S^{2-} ion and the SH^- ion. The overall limiting reaction can be summed as such:

$Na^+ + SH^-$ ----> NaSH

The Sulfatreat™ process involves contacting the feed stream with Iron oxide, which reacts with H2S to form Iron Sulfide and water. The passive process requires repeated changeout as the Iron Oxide is gradually spent.

5.7.3 Design Outlines and Parameters

A more efficient contactor was proposed which utilizes a venturi system. This replaced the original chemical feed pump and static mixer used previously.

The design parameters aim to achieve a compromise between adapting the existing caustic scrubbing process and the Sulfatreat™ process, utilizing the relative strengths of both processes.

To utilize the low cost of caustic for bulk removal of H_2S, the gas streams are contacted with caustic first, with a fixed number of stages until the cost per weight ratio deem the process uneconomical. The Sulfatreat™ process is known for its ability to remove much lower concentrations of H_2S from a feed stream. Thus, it was proposed that the gas stream be first contacted with caustic to a manageable level of H_2S concentration followed by treatment by Sulfatreat™

The H_2S concentration is reduced to 250 ppm, which is further reduced to < 4 ppm by Sulfatreat™. The net cost per pound of Sulfur is $0.43, with a yearly operating cost of $226,000. This is significantly lower than the original four-stage process, which yielded $0.74 per pound of Sulfur and a yearly operating cost of $393,000.

5.7.4 Start-up and Operation

Start-up for the improved H_2S caustic scrubber was in June 1996 and has experienced no major operating difficulties thus far.

5.8 Installation of a Steam Generator operating on produced gas

5.8.1 Scenario

Tidelands produces approximately 2000 MCFD of gas with a heating value of 550 to 1000 Btu/scf. This translates to 62 MMBtu/hr of potential fuel. The produced gas had no commercial value, and flaring of the gas was not permitted by South Coast Air Quality Management District (SCAQMD) regulations. Thus, all produced gas has to be fed into a generator (essentially an incinerator) which would operate at or near maximum capacity. Based on these external constraints as well as the current steam requirement for injection and the availability of gas, it was proposed that the optimal set-up would allow for a 50 MMBtu/hr steam generator.[A16]

The SCAQMD adopts a policy of applying BACT (Best Available Control Technology), which requires a Continuous Emissions Monitoring System (CEMS). Thus, the following NO_x burner emissions rates have to be submitted real time via a modem in accordance to SCAQMD rules and regulations: NO_x, wet O_2, dry O_2, stack gas flow rate, steam output, fuel flow rate, and FGR (Flue Gas Recirculation) rates.

5.8.2 Design Outline and Parameters

A used Stuthers steam generator was rebuilt and retrofitted with a low NO_x burner, designed to burn fuel with a heating value of 550 But/scf. The burner was designed and built by North American Manufacturing company and was guaranteed by the manufacturer to emit less than 9-ppm NO_x without using selective catalytic reduction with ammonium injection (SCR). The generator was rated at 58,500 lb-hr with a maximum working pressure of 1700 psi.

The low NO_x burner is a multi zone and multi burner design. NO_x control is achieved by the following means; combustion occurs in a controlled zone which minimizes NO_x, CO and VOC production; maintaining the air-fuel mix at lean condition (typically 50-60% excess air) which allows for lower operating conditions and lower NO_x emissions; and the elimination of violent air and fuel mixing which also aids at reducing NO_x emissions. Additional fuel (or secondary fuel) is added in the multi-port secondary burner outside the primary production zone. Thus, the ratio of secondary and primary fuel can be manipulated to achieve the desired optimal operating conditions with respect to generator efficiency or reducing NOx levels.

The control system setup involves a GE 90-30 programmable logic controller (PLC) with a Wonderware software program. The input variables involved for control, trim, alarms and/or system shutdowns are: fuel delivery pressure, steam quality, discharge pressure, primary burner fuel rate, total fuel rate, combustion O_2 concentration, stack NO_x concentration, air inlet rate and FGR (Flue Gas Recirculation) rate. The flame guard controller used is a stand-alone unit -from Honeywell - for safety purposes.

5.8.3 Startup

Instability in the upstream processes was noted and was attributed to surges from the new upstream oil/water/gas separation equipment. Fuel consumption was erratic due to debugging of the new dehydration system. The fuel surges and compositional changes caused the generator to shut down as the controllers were not designed for such erratic behavior.

As a result, a twofold solution was proposed:

Firstly, the upstream processes had to be stabilized with the usage of surge tanks, retuning control loops, modifying operational procedures and closely monitoring each subprocess.

Secondly, a Btu analyzer was installed on the fuel supply and the control program was reformatted to allocate greater liability to the fuel intake pressure, and charge rate. The proposed should, in theory, eliminate sudden fluctuations in steam quality, as well as shut downs caused by rapid fluctuations in Btu value and/or specific gravity.

5.8.4 Performance testing

The SCAQMD guidelines for performance testing of the steam generator are 15ppm NO_x, 10 ppm CO. In addition, CEMS are required. On 9 October 1996, stack testing was conducted which was verified by a third party, World Environmental. The emissions rates were 5.44ppm NO_x, 1ppm CO, without FGR usage and all essentially all waste gases were consumed. Also, the generator was set for smoothest run, and not for minimum NO_x. NO_x values of 4ppm have been obtained in past operations. Also, when the NO_x burner's secondary burner was down, NO_x levels were still below 15ppm without FGR. However, erratic swings from 5-14ppm are typical.

5.9 Applying the Novel Sand Consolidation Well Completion Technique

5.9.1 Brief Overview

The unconsolidated nature of the turbidite sands in the various regions of the Wilmington Field result in producability problems downstream. Thus, a means of limiting sand production has been of paramount importance with regard to operations in the said field. The sands themselves are comprised dominantly of subangular grains of quartz and plagioclase feldspar.

Work concerning the Sand Consolidation Well Completion Technique is largely characterized under Operational Management, and is thus only briefly mentioned here. However, it should be noted that the Sand Consolidation technique has been applied to: 13 vertical wells in the Tar Zone; 2 horizontal wells in the Tar Zone in Fault Block I; 4 horizontal wells in the Tar Zone of Fault Block II-A (DOE project); and 5 horizontal wells in the Tar Zone of Fault Block V. After 5 years, with the notable exception of 1 horizontal well in fault Block I, minor or no sand problems have been experienced, with no observable impairment to well productivity.

5.10 A 2100ft Steam Line Operating Under a Ship Channel, an Update

5.10.1 Introduction

The commencement of steam injection in the Tar Zone of Fault Block II-A on Terminal Island necessitated a steam supply from the mainland. Thus, the under channel steam transmission line was constructed and placed in service since December 1995.[A9] Much of the design parameters have been covered in the previous reporting period. Figure shows the location of the steam transmission line.

5.10.2 Update

To date, the steam transmission line has been in service with no major problems encountered.

5.11 High Temperature Downhole Electric Submersible Pumps

Union Pacific resources pioneered the development of an ESP that can operate in the high temperature environment of a steamflood. Tidelands continued the high temperature pilot work when it took over steamflood operations in 1994.[A2] The high temperature ESPs have performed well in temperature ranges below 350oF, but have experienced short operating lives under higher temperatures due to the failure of the pothead connection.

Due to the expense of running ESP pumps compared to conventional pumps, it was decided to suspend the use of high temperature ESPs.

5.12 Conclusion

Reservoir management within this reporting period focussed on the four horizontal wells (UP-955, UP-956, 2AT-61 and 2AT-63) drilled pseudo-SAGD fashion the previous year in the Tar Zone of Fault Block II-A. The Thermal recovery Program initiated this reporting period focussed on empirical comparative studies on the following thermal recovery methods:

1. Cyclic steam stimulation
2. Hot water alternating steam (WAS) drive
3. Continuous Steam Injection

As shown in Figures 5.4.1-1 and 5.4.1-2, 2AT-61 and 2AT-63 underwent cyclic steam injection, and were on permanent steam injection at the close of the reporting period. UP-955 and UP-956 underwent cyclic steam stimulation, and experienced a noticeable increase in gross and net production towards the close of the reporting period, as the effects of the continuous steam injection from 2AT-61 and 2AT-63 become apparent.

Four existing steam injection wells (2AT-32, 2AT-33, 2AT-40 and 2AT-41) were converted to hot water injection from March 1995 to February 1996. Four additional steam injectors (2AT-36, 2AT-37, 2AT-44 and 2AT-45) were converted to hot waterflood injection in February 1997. Reservoir tracers were injected into wells 2AT-32 ("T" sand) and 2AT-33 ("D" sand) on February 14 1997. This is described in section 3.3.2 of this report.

The produced gas from steamflood and waterflood require treatment to reduce the H_2S and mercaptan concentrations. An original four-stage caustic scrubber was already in place, although a cost analysis of the latter two stages was indicative of a high cost savings potential. The Sulfatreat™ process was adapted downstream to a two-stage caustic contactor vessel. This set-up was deemed the most cost-effective option following an economic analysis. At the close of the reporting period, the unit has had only one Sulfatreat™ changeout.

Produced gases from the Fault Block II-A Tar zone, which were unsuitable for commercial usage were adapted for use in a new thermal recovery project through the installation of a 7ppm NOx 50MMBtu/hr oil field steam generator. Of note is the inherent difficulty of operating a variable Btu gas source downstream of the new caustic scrubber unit mentioned above. However, this was accomplished without significant operational difficulties.

6 OPERATIONAL MANAGEMENT

6.1 Introduction

Thermal recovery operations in Fault Block II-A of the Wilmington Field have met with operational difficulties peculiar to its geology. Thermal operations have been subject to premature well and downhole equipment failure as a result of early steam breakthrough and sanding. These problems are commonplace in other SBC (Slope Basin Clastic) reservoirs with heterogeneous and unconsolidated sands. Additionally, the high reservoir pressure and associated high steam temperature in the Wilmington Field aggravate the wellbore and equipment problems associated with early steam breakthrough.

To optimize the cost-effectiveness of thermal operations, this project will focus on the following approaches to minimize and alleviate operational problems:

1. Controlling sanding in producing wells through the use of alkaline hot water/steam injection to consolidate the formation sands.

2. High temperature core and formation fluid studies to understand the types and origins of the gases and mineral scales observed in the field.

6.2 Applying the Novel Sand Consolidation Well Completion Technique

6.2.1 Introduction

The unconsolidated nature of the turbidite sands in the Wilmington Field result in producability problems downstream. Thus, a means of limiting sand production has been of paramount importance with regard to operations in the said field. The sands themselves are comprised dominantly of subangular grains of quartz and plagioclase feldspar.

A more conventional method applied previously involves using an opened-hole gravel-packed and slotted liner completion. However, in the interest of reducing capital costs, it was proposed to use the alkaline hot water/steam sand consolidation technique for completing the new horizontal wells. The technique was first applied to thirteen vertical wells in the Fault Block II-A, Tar Zone and two horizontal wells in the fault block Tar zone before its application in the four DOE project horizontal wells (UP-955, UP-956, 2AT-61 and 2AT-63) in the Tar Zone of Fault Block II-A. The interest in the sand consolidation technique is in the actual detailed geochemistry surrounding the process. Consolidated sand samples were found encrusted to the steam injection tubing tail following a cyclic steam stimulation job in well UP-955. The samples showed bonding of the sand grains with high temperature cements not found in the native formation rocks, but geochemically created through the dissolution of formation minerals from the hot alkaline in the condensate phase of the steam.

Various permutations of the technique have been applied for purposes other than new well completions. The first producer given the sand consolidation technique was well UP-779. It was a deeper zone producer, which was recompleted into the “D” Sand of the Tar Zone in Fault Block II-A, placed on steam injection in December 1991 and performed equivalent to offset steam drive producers. The well was subsequently given an HCl acid job which successfully removed scale damage without affecting the consolidated sands. In October 1994, UP-932 successfully underwent the Sand Consolidation technique to repair enlarged slots in its slotted liner. UP932 production was restored to its previous production rates without sand production.

After five years, with the notable exception of one horizontal well in Fault Block I, all of the Sand Consolidated wells have experienced minor or no sand problems and have had no observable impairment to well productivity.

6.2.2 Sand Consolidation Procedure - A Brief Description

A well with cemented casing is first selectively perforated with ¼in. to ½in. perforations, preferably ¼in., with the number of perforations needed based on attaining limited entry conditions for the steam rates and pressures available. To minimize heat loss, thermally insulated tubing, an expansion joint and a thermal packer are run into the well. Steam quality should range from 60-80%, which provides a highly alkaline (pH = 10-12) liquid phase. The steam rates and pressures must be high at the wellface to ensure that each perforation is taking steam and that the steam temperatures are high enough (> 540^{o}F) to geochemically create the cements for bonding the sand grains. The empirically based minimum steam volume necessary to achieve sand consolidation is 750 barrels of cold water equivalent steam per ¼in. perforation based on wellbore samples collected from well UP-955.

It is believed that the hot alkaline water in 80% quality steam causes silica dissolution which bonds the sand grains and controls sand movement through the wellbore. Limited entry perforating assures present and future steam injection profile control. It has been shown that the rates and volumes in a production well completed with perforations in the sand consolidation technique is equal to or better than a well completed with a gravel-packed liner over a similar interval. This indicates that the Sand Consolidation Technique is creating secondary porosity through the selective dissolution of formation fines and thus increasing permeability. .

6.2.3 Application of Sand Consolidation Technique on UP-955

UP-955 is a horizontal well completed and cyclically steamed during the last reporting period and is one of the four wells of particular interest to the DOE project. The horizontal section of the well was drilled in the “D” Sand, within the Tar Zone of Fault Block II-A, and completed using the Sand Consolidation technique.

The well was completed with a total of 48 perforations from 3915’ to 4430’, which were 0.3” in diameter. A casing scraper was then run and the casing was circulated clean with clean water. Sand consolidation began in June 1996, with the injection of 80% quality steam through insulated tubing, an expansion joint and a thermal packer set at 2398’ with a tubing tail to 3907’. See figure 6.2.3 for a schematic diagram.

The Sand Consolidation treatment required 36,000 CWE Barrels of steam and an additional 78,000 CWE Barrels of steam were injected for the Huff “N” Puff cycle. The well was then shut-in for a 5 week steam soak. In October 1996, the insulated tubing was pulled and a coating of formation sand was found cemented to the tubing tail from 2963’ to 3401’. Samples of the sand were analyzed using thin sections, x-ray diffraction and a scanning electron microscope (SEM).

The sand cemented onto the tubing tail is believed to be the result of unconsolidated sands entering the wellbore early in the cyclic steam job when the steam source underwent a shutdown on July 13 and 14. This occurred after cumulative injection was 11,500 CWE bbls of steam, approximately 30% of the volume needed to perform a successful sand consolidation on the 48 perforations. The remainder of the cyclic steam injection job proceeded without problems.

The well was placed on production in November 1996 at an initial rate of 29 BOPD and 1037 BWPD, and by March 1997, had peaked at 80 BOPD and 1450 BPD gross, with a 1700-ft fluid level over the pump. A vertical well completed over a 280-ft interval with an opened-hole,

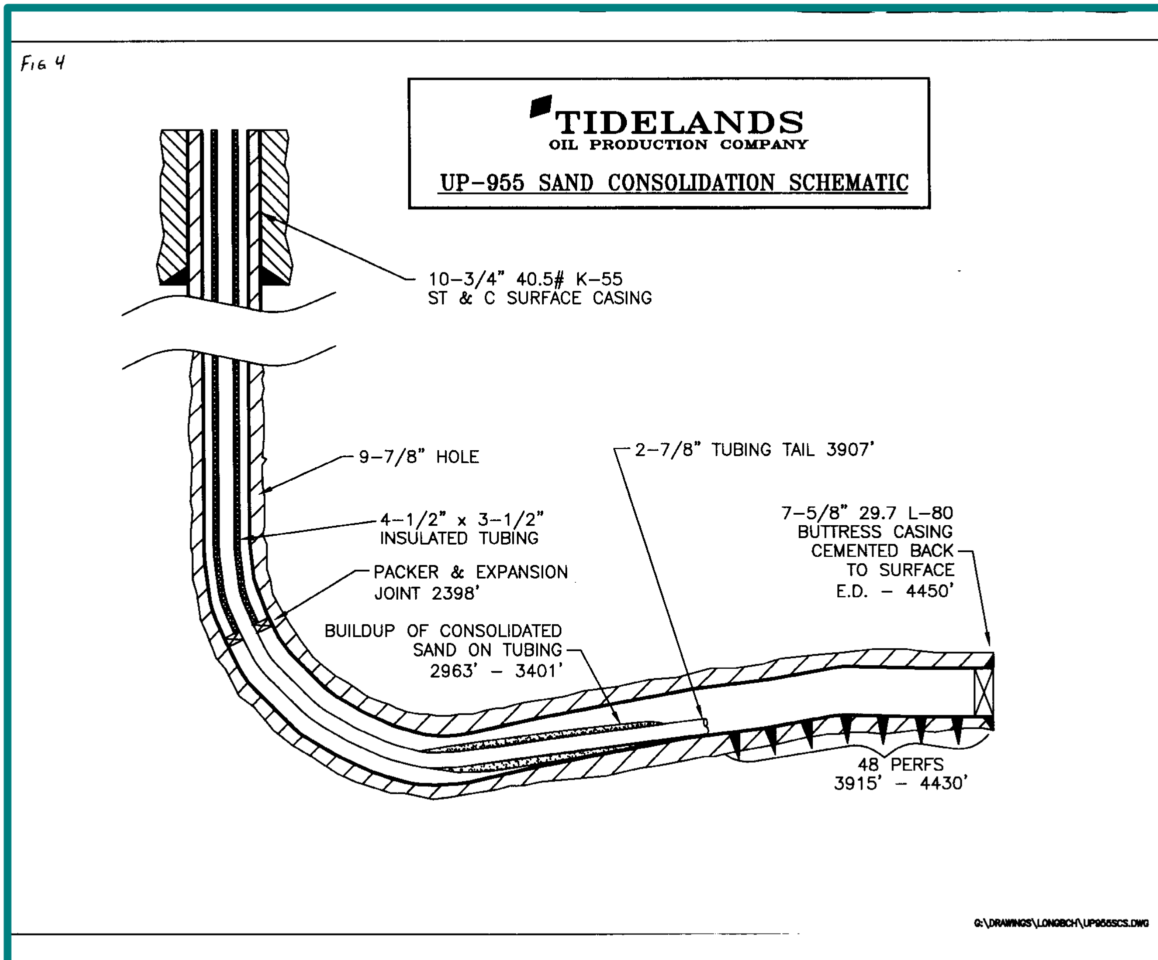


Figure 6.2.3 Wellbore Schematic for UP-955 showing Sand inflow encrusted onto tubing tail.

gravel-packed and slotted liner completion typically produces 1000 BPD gross. In effect, 48 – 0.3in. holes were too many by a factor of two and the high fluid level is hurting net oil production.

6.2.4 Analyses of Sand Consolidation on UP-955 tubing tail by David K. Davies and Associates

The thin section, x-ray diffraction and SEM work revealed that the grain composition and grain size of the artificially cemented sands were the same as the formation sands and entered into the wellbore by means of the open perforations. The sand grains flowed down the casing annulus between the casing and tubing tail, completely surrounding the tubing tail, as shown in Figure 6.2.3. The cemented sand samples indicated the presence of three concentrically arranged layers as described below and shown in Figure 6.2.4-1:

Layer 1 was the closest to the tubing wall and consisted of sand grains bonded with silica cement (SiO_2). The 1 to 3 mm thick layer had a low porosity of < 1%, as determined from thin section analysis, and was considered to be essentially impermeable.

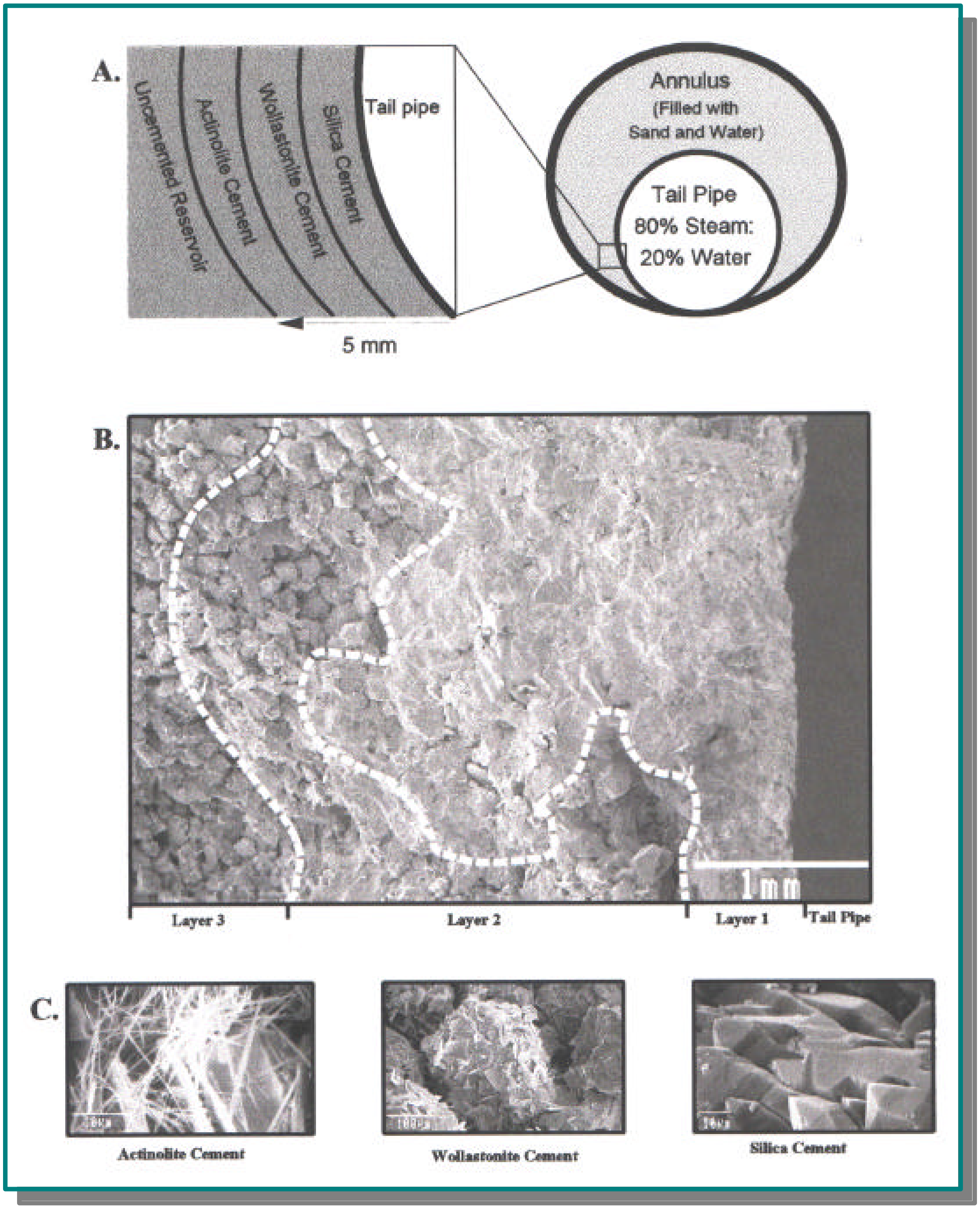


Figure 6.2.4-1 UP-955 tubing tail sample showing the three cement layers and the pictures of the three cement types bonding the sand grains.

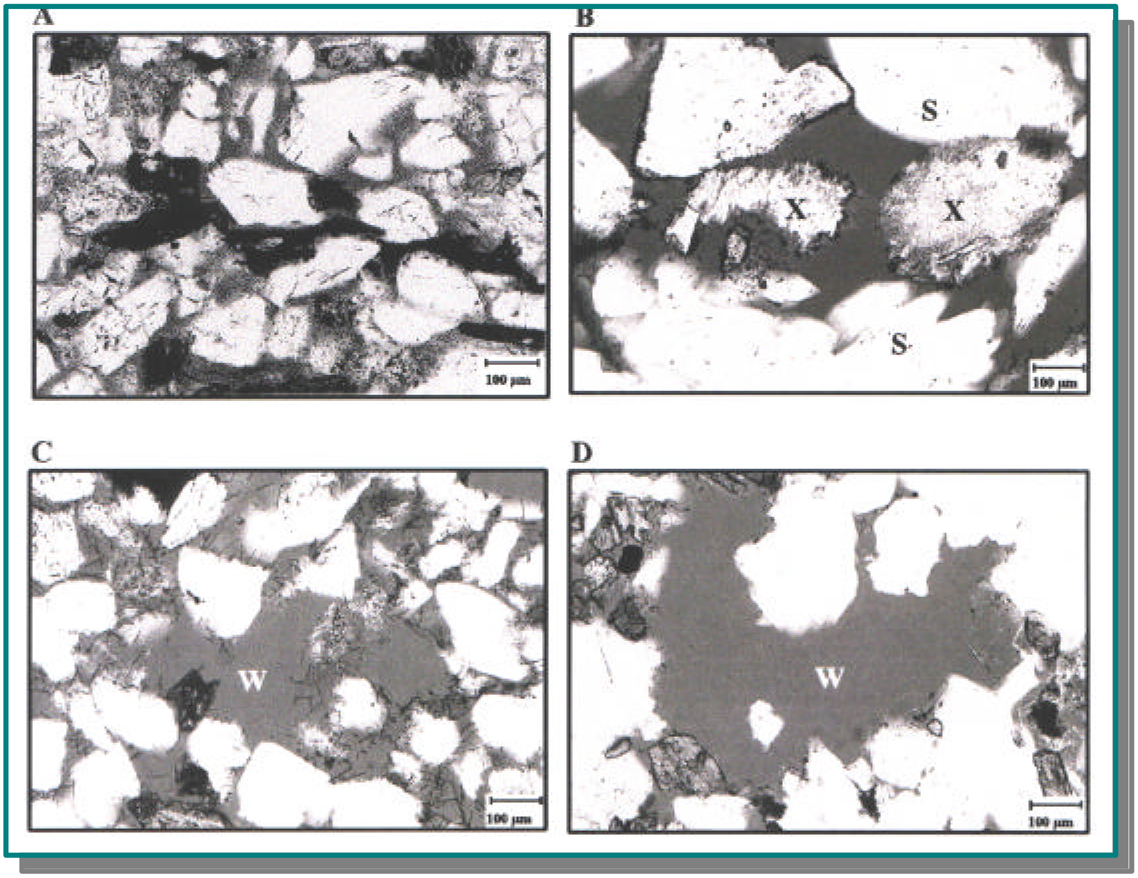


Fig. 6.2.4-2 Thin section photomicrographs of pore structure. Sand grains are white and black; pores are gray areas between sand grains.
A. Actual pore structure of Tar Zone Sands (pre-steam core).
B. Partial dissolution of unstable grains (X).
Note: irregular grain outlines. Surrounding sand grains are relatively large due to precipitation of silica cement (S).
C&D. Dissolution wormholes (W) produced through leaching of pre-existing silicate grains.

Silica cement is a low temperature cement which precipitates at about 300^{o}F. Layer 1 is believed to have been initially bonded with high temperature Layer 2 cements and subsequently covered with Layer 1 cements when cyclic steam injection ceased and the tubing filled with kill fluids.

Layer 2 formed above Layer 1 and is 1 to 3 mm thick. This layer consisted of artificially cemented sand grains, primarily by a complex Calcium Silicate ($CaSiO_3$) mineral. The crystals formed a plate structure, which extended from one grain to the next. This resulted in a high porosity of > 25% as determined by thin section analysis, however, a reduced permeability results from cemented pore throats. This layer is loosely referred to as the Wollastonite layer, as Wollastonite is the closest known mineral to this artificially-made cement. Wollastonite is a high temperature cement which precipitates at about 540-580^{o}F.

Layer 3 was the outermost layer and was 1 to 3 mm thick. The sand grains were loosely cemented by synthetic accicular (needle-like) crystals of another complex calcium silicate mineral. This layer has a high porosity of > 25% as determined by thin section analysis. Permeability is higher than Layer 2 (by visual analysis), but like Layer 2, cannot be accurately determined reliably, as the layers are too thin. This layer is loosely referred to as the Actinolite layer, as Actinolite is the closest known mineral phase of this artificially-made cement. Actinolite is also a high temperature cement which precipitates at about 480-500^{o}F.

A closer analysis of the Wollastonite and Actinolite layers reveals the presence of loose bonds between the sand layers. This was due to the habit (shape) of the said crystal layers.

The reactions, which occurred, were the result of dissolution (leaching) of the sand grains by the high pH steam condensate and precipitation (nucleation and crystal growth) of cements as wellbore temperatures decreased. In particular, the dissolution reactions show selectivity towards grains with inherent planes of weakness and high surface areas. In this case, feldspathic grains appear to be extensively leached as shown in Figure 6.2.4-2. Due to the high abundance of feldspathic grains in the Tar Zone, extensive dissolution is apparent in the cemented sand samples, especially where several feldspathic grains occur in series. This group dissolution forms wormholes, which increase both absolute and relative oil permeability within the cemented areas. These dissolution wormholes appear to form only in areas of high heat transfer - immediately adjacent to the well bore in steam injection wells.

6.2.5 Results and Conclusions

The loosely bonded nature of the Wollastonite and Actinolite layers implies that the rock framework is stabilized but not rigid. Thus, the skin around the perforation is correspondingly loosely cemented and may fail in the presence of high differential pressures across the formation face.

Also, the permeability in the skin layer is reduced (from visual observation), with the notable exception of regions of dissolution. These regions of dissolution form wormholes, which permit large diameter fluid pathways from the reservoir rock to the wellbore. However, such permeability enhancement is dependent on the abundance of feldspar, as is found in this formation.

The Novel Sand Consolidation Technique has seen successful applications on 13 vertical wells, 9 horizontal wells, and one repaired damaged liner in the Tar Zone of Fault Blocks I and II. After 5 years of production, no major sand consolidation problems have been experienced in these wells.

The success of the Sand Consolidation well completion technique has resulted in the successful transfer of this technology to other fault blocks and zones in the Wilmington Field. This completion technique has been applied in five horizontal wells for a steamflood project in the Tar Zone of Fault Block V, one well recompleted in the Tar Zone in Fault Block V in the waterflood area, and two wells recompleted to the Upper terminal zone waterflood in Fault Block V. [A17]

6.3 Studies on High Temperature Core Work

The high temperature core work began on measuring rock compaction due to steamflooding. This aspect of the core work was added to the original proposal to perform steam pot tests and measure the geochemical effects of high temperature steam on the reservoir rocks and fluids which will be started the following work year. All of the special core work above will be used in the thermal reservoir simulation model.

The results of the high temperature core work will aim to establish temperature limits with regard to operations and effectively establish operating temperature thresholds.

This will be accomplished when the effects of temperature on reservoir rocks and fluids are better understood.

6.4 Minimize Carbonate Scale Problems

Samples of fill (sand, scale, gravel pack) from existing steamflood producers[A20,C5] were analyzed to determine possible reasons for formation damage and liner plugging in wells. Detailed thin section, scanning electron microscope and x-ray diffraction work was performed on the samples. The types of scales identified were calcites, dolomites, barites, anhydrides, and magnesium-silicates. A detailed discussion of scaling was provided in the previous Annual Report.

7 PROJECT EXPANSION

The Thermal project will be expanded to the remainder of the D1 sand in the Fault Block II-A Tar Zone in Phase 2 of this project, based on the results of reservoir characterization, reservoir simulation and pilot testing in Budget Period 1. It is anticipated that four horizontal producers, four horizontal injectors, and three horizontal wells will be installed during the second phase.

The expansion project has a drainage area of approximately 83 acres and a net oil sand thickness of 75 ft. The remaining oil saturation after waterflooding is estimated to be 66%. The remaining oil in place is estimated to be 9,625,000 barrels of oil. Projected recovery from the expansion project is estimated to be 5,100,000 barrels of oil. The total pilot and expansion projected oil recovery is estimated to be 7,117,000 barrels.

The overall project is expected to take seven years to complete. The expansion project is scheduled to start in the first quarter of 1999 and proceed through 2002.

8 TECHNOLOGY TRANSFER

8.1 Introduction

Consistent with the intent of the project, the new technologies detailed in the preceding pages were made available to the petroleum engineering community through technology transfer activities, promulgation, the utilization of a CD-ROM, and web page publishing. Thus, the project team participated in numerous activities throughout the reporting period - most notably through their heavy involvement in the 1997 Western Regional Meeting of the Society of Petroleum Engineers to be held in Long Beach.

In addition, publicity was generated outside of the petroleum engineering community through articles published in the Los Angeles Times, the American Oil and Gas Reporter and Compressed Air Magazine.

The opening of the West Coast Petroleum Technology Transfer Council office at the University of Southern California was very significant, in view of the added accessibility to the work performed by the project team to regional operators.

8.2 Western Regional Meeting of the Society of Petroleum Engineers

This year, the Western Regional Meeting (WRM) of the Society of Petroleum Engineers was held in the City of Long Beach from the 23rd to the 27th of June. Project team member, Scott Hara was the General Chairman of the WRM while Dr. Iraj Ershaghi and Dr. David K. Davies were instructors on “PTTC Intermediate Internet Training” and “Identification and Prevention of Formation Damage through detailed Rock Analysis”, respectively.

The PTTC Intermediate Internet Training workshop was held at the Petroleum Technology Transfer Council West Coast Office, located at the University of Southern California. The aim of the workshop is to provide individuals in the petroleum community with a select source of sites by which petroleum industry information can be accessed, as well as familiarizing these individuals with the necessary hardware and software needed to access these on-line databases.

The workshop on Identification and Prevention of Formation Damage through detailed Rock Analysis aims to provide an overview of formation damage identification, prevention and correction to petroleum engineers and geologists. In relation to the Class III DOE project, the workshop emphasizes the importance of rock and fluid characterization in successful field operations.

A field trip entitled “A Visit to the Giants of the Los Angeles Basin” will be jointly conducted by project team members Donald Clarke and Chris Phillips, and George Ottot of THUMS Long Beach Company on June 24. This field trip focuses on the production histories as well as the specific difficulties encountered with production from the Wilmington, Huntington Beach and Long Beach Oil Fields. In addition, a field trip guidebook of the same title was generated with excerpts from papers detailing the history, operational difficulties and problem mitigation of the oil fields. The field trip and accompanying guidebook was revised from the trip entitled “Old Oil Fields and New Life: A Visit to the Giants of the Los Angeles Basin” conducted at the 1996 AAPG Annual Meeting.

Also, 6 paper presentations and 3 GEMS sessions are scheduled to be conducted by members of the project team.

8.3 1996 American Association of Petroleum Geologists Annual Meeting

The AAPG meeting was conducted in San Diego in May 1996. The following presentations were made by the project team in relation to the Class III DOE project:

Dr. David K. Davies conducted a poster session entitled "Flow Unit Modeling in Complex Reservoirs" as well as a presentation entitled "Mineralogy and Origin of Well-Bore Scales in an Active Steamflood: Tar Zone, Fault Block II-A, Wilmington Field, CA."

Donald Clarke, Chris Phillips and Linji An gave poster session on "Tertiary Development of Heavy Oil Sands Through Thermal Stimulation in the Wilmington Oil Field, CA: a Geological Perspective."

Scott Hara and Julius Mondragon gave a poster session presentation entitled "A Novel Sand Consolidation Completion Technique Using Alkaline Steam Injection in the Tar Zone, Wilmington Field, CA."

Also, a field trip was conducted entitled "Old Oil Fields and New Life: a Visit to the Giants of the Los Angeles Basin", and a guidebook of the same name was prepared.

8.4 1997 American Association of Petroleum Geologists Annual Meeting

Th upcoming AAPG Annual meeting is scheduled to be held in Dallas, TX on the 7-9th April 1997. The following project members will be making presentations:

Donald Clarke, Chris Phillips and Linji An will give a poster session presentation entitled "Horizontal Wells in a clastic oil field with Intraformational Compaction"

Linji An, Dr. I. Ershaghi, Donald Clarke and Chris Phillips will give a poster session entitled "Sealing Behavior of Normal Faults in Fault Block II, Wilmington Field, CA."

In addition, an exhibition booth will be set up and run by Dynamics Graphics and Chris Phillips on "Earth Vision Software Solutions for Structurally Consistent 3-D Geologic Modeling and 3-D Well Placement Planning".

8.5 PTTC Related Activities

A problem identification workshop was conducted on the 20th, 25th and 26th of November, 1996 in Bakersfield, Long Beach and Ventura respectively. Dr. Iraj Ershaghi served as coordinator of the workshop and Mark Kapelke gave an oral presentation entitled "Multimedia and Technical Transfer."

The West Coast PTTC Office located at the University of Southern California in Los Angeles was officially inaugurated on the 6th of December 1996. The opening ceremony speaker was Dr. Iraj Ershaghi and in addition, the following brief presentations were made: "Tar Zone Reservoir Stimulation on Primary Production" by Zhengming Yang; "Tar Zone Reservoir Material Balance Studies" by Yucel Akkutlu and Dr. Lyman Handy; "Geologic 3-Dimensional Modeling" by Linji An; "Stochastic Reservoir modeling" by Chang-An Du and an update on the CD-ROM project by Mark Kapelke.

A PTTC workshop entitled "CA Geology; With or Without Computer Graphics" was conducted on the 15th of January 1997, with Dr. Iraj Ershaghi and Donald Clarke as coordinators.

The following presentations were made: “Geological Control on Reservoir Productivity” by Dr. projects, Thermal Flood, Tar Zone, Wilmington Oil Field”.

A half day workshop entitled “3-D geologic Modeling: Theory and Application” will be conducted at the PTTC West Coast office on 2 May 1997 by Jeff Schwalm and John Perry of Dynamic graphics. This workshop features the EarthVision™ software which was heavily used for reservoir characterization work described in the preceding chapters.

8.6 Other Conferences and Seminars

In addition to those described above, the project team also made presentations at the following events throughout the reporting period:

8.6.1 SPE/DOE Symposium in Tulsa, OK

Dr. David K. Davies gave a presentation entitled “Nature, Origin, Treatment and Control of Wellbore Scales in an Active Steamflood, Wilmington Field, CA”, at the above event on the 21-24th April 1996.

8.6.2 Status report to DOE representatives

The project team members gave a presentation and a status report at Tidelands Oil Production Company’s office on 19th September 1996.

8.6.3 SPE LA Basin Environmental and Study Group Forum

Steve Siegwein gave a presentation entitled “review of Recent Well Drilling Activities by THUMS Long Beach Company and Tidelands Oil Production Company” on September 25, 1996, at the Long Beach Petroleum Club.

8.6.4 1996 SPE Annual Technical Conference

Dr. I. Ershaghi and M. Hassibi gave a joint presentation entitled “A Neural Network Approach for Correlation Studies in a Complex Turbidite Sequence” at the above event on the 6-9th October in Denver, CO.

8.6.5 8th Annual Energy Week Conference and Exhibition

Rick Cassinis, Sean Massey and Stuart Hassler gave a joint presentation entitled “Improved H_2S Caustic Scrubber” on January 30, 1997 at the above event sponsored by API and ASME in Houston, TX.

8.6.6 1997 SPE International Thermal Operations and Heavy Oil Symposium

Rick Cassinis gave a presentation entitled “a 2100ft, 14” steam line under a Ship Channel” at the above event on the 10-12th of February in Bakersfield, CA.

8.6.7 4th International Reservoir Characterization Technical Conference

Dr. I. Ershaghi and M. Al-Qahtani gave a presentation entitled “Characterization and Estimation of Permeability Correlation Structure from Performance Data” on 2-4th March 1997, at the above event sponsored by the DOE, BDM and AAPG.

8.7 Web Site and CD-ROM project

A home page on the USC service provider has been set up in conjunction with the existing account for the Petroleum Engineering Program at USC. The ongoing DOE projects on the West Coast are comprehensively summarized and can be accessed at:

http://www.usc.edu/dept/peteng/doe.html

In addition, the summarized content of the previous year's annual report can be accessed at:

http://www.usc.edu/dept/peteng/topko.html

The web sites are also linked to a significant number of petroleum related sites both in industry and in academia, which includes the national PTTC site.

The CD-ROM project is essentially a collection of interviews and presentations saved as brief movie clips detailing the scope of operations at Tidelands Oil production related to the Class III DOE project. The CD-ROM is currently viewable using an Apple Macintosh Operating System, and an IBM viewable version is scheduled to be completed by the upcoming SPE Western Regional Meeting in June.

8.8 Papers and Publications

A listing of papers, both published and pending publication has been cited in the following chapter, which details the references. Most notably, there were three interviews conducted by the Los Angeles Times[A8,B2-4] as well as interviews with Compressed Air Magazine[B6] the Petroleum Engineer Magazine[B1] and the American Oil & Gas Reporter.

The article entitled "Drilling in Disguise" was in the Metro Section of the Los Angeles Times, dated November 15, 1996. The report details the general scope of oil related operations in the Wilmington Oil Field. project member Don Clarke provided the technical expertise for the report. Project team member and chief geologist at Tidelands Oil production, Chris Phillips was interviewed for an article entitled "In Geological Time, He's Ancient", by the Los Angeles Times. The article, which appeared in the Business Section on December 9, 1996, details the scope of his job within the oil industry in the Los Angeles Area, with special reference to Tidelands Oil Production.

The interview entitled "Coaxing Crude from the Ground" appeared in the March 1997 issue of Compressed Air Magazine. Project team member Iraj Ershaghi provided the technical input for the report. The paper entitled "3-D Modeling, Horizontal Drilling... Give New Life to Aging Fields", by Don Clarke, Chris Phillips and Linji An was published in the September 1996 issue of the American Oil & Gas Reporter. Steve Bell of Hart's Petroleum Engineer conducted an interview with project team member, Scott Hara on the DOE Class III projects with specific reference to Tidelands.[B26]

9 REFERENCES

The following presentations, made at technical transfer activities and miscellaneous conferences throughout the reporting period, are cited in this report:

A. Papers, Poster Sessions, Reports, CD-ROMs, other non-reference materials generated by DOE Project.

[A1] Sameer Joshi, L.M. Castanier and W.E. Brigham (Stanford University), Mike C. Wood (Union Pacific Resources Co.),:"Steamflooding a Waterflooded Reservoir - Performance Evaluation Prediction", SPE Paper 29669 presented at the 1995 Western Regional Meeting of the Society of Petroleum Engineers in Bakersfield, CA, 8-10 March 1995.

[A2] Mike C. Wood, Bruce Laughlin, Doug Fuller and Robert Fickes (Tidelands Oil Production), "The Use of Downhole Submersible Pumps in a High Temperature Steamflood", SPE paper 29507, presented at the 1995 Society of Petroleum Engineers Production Operations Symposium in Tulsa, OK, April 1995.

[A3] David Crane, William R. Barry II (Digital Petrophysics Inc.), :"Database preparation for Wilmington Field, Fault Block II-A - Tar Zone" dated 15 June 1995.

[A4] Herman E. Schaller,:"Study of Water Injection Surveys, Tar Zone, Fault Block II, Wilmington Field" dated 8 November 1995.

[A5] David Crane (Digital Petrophysics Inc.), report dated 12 March 1996 detailing list of well data which had undergone checking and processing.

[A6] Donald Clarke (City of Long Beach), Chris Phillips (Tidelands Oil production), :"Old Oil Fields and New Life: A Visit to the Giants of the Los Angeles Basin", field trip and guidebook of 14 papers, given at the 1996 Annual Meeting of the American Association of Petroleum Geologists (AAPG) in San Diego, California, May 1996. The guidebook is being revised for a tour to be given at the 1997 Western Regional Meeting of the Society of Petroleum Engineers.

[A7] Donald D. Clarke (City of Long Beach), Chris C. Phillips (Tidelands Oil Production), and Linji An (University of Southern California), :"Tertiary Development of Heavy Oil Sands Through Thermal Stimulation in the Wilmington Oil Field, California: a Geological Perspective", presented at the 1996 Annual meeting of the American Association of Petroleum Geologists (AAPG) in San Diego, California, May 1996.

[A8] Donald D. Clarke (City of Long Beach), Chris C. Phillips (Tidelands Oil Production), and Linji An (University of Southern California), :"3-D Modeling, Horizontal Drilling... Give New Life to Aging Fields", pages 106-115, American Oil & Gas Reporter, September 1996 issue.

[A9] Rick Cassinis (Tidelands Oil Production), : "2100-foot, 14-inch Steam Line Under a Ship Channel", SPE Paper No. 37530, to be presented at the 1997 SPE International Thermal Operations and Heavy Oil Symposium in Bakersfield, CA, 10-12 February 1997.

[A10] Donald D. Clarke (City of Long Beach), Chris C. Phillips (Tidelands Oil Production), Linji An (University of Southern California), :"Horizontal Wells in a Clastic Oil Field with Intraformational Compaction", poster session presentation at the 1997 American Association of Petroleum Geologists (AAPG) Annual Meeting in Dallas, TX, 7-9 April.

[A11] Iraj Ershaghi, Linji An (University of Southern California), Donald D. Clarke (City of Long Beach), Chris Phillips (Tidelands Oil Production), :"Sealing Behavior of Normal Faults in Fault Block II, Wilmington Oil Field, California", poster session presentation at the 1997 American Association of Petroleum Geologists (AAPG) Annual Meeting in Dallas, TX, 7-9 April.

[A12] Donald D. Clarke (City of Long Beach), Chris C. Phillips (Tidelands Oil Production), Linji An (University of Southern California), :"Tertiary Development of Heavy Oil Sands through Thermal Recovery in the Wilmington Oil Field, California: An Update and Some New Challenges", Oral presentation at the 1997 American Association of Petroleum Geologists (AAPG) Pacific Section Convention in Bakersfield, CA, on 14-16 May.

[A13] Donald D. Clarke (City of Long Beach), Chris C. Phillips (Tidelands Oil Production), Linji An (University of Southern California), :"Reservoir Characterization Using Advanced 3-D Computer Modeling Technology: A Case Study of the Fault Block II in Wilmington Field, California", Electronic poster session at the 1997 American Association of Petroleum Geologists (AAPG) Pacific Section Convention in Bakersfield, CA, 14-16 May.

[A14] Iraj Ershaghi, Lyman L. Handy, Yucel I. Akkutlu (University of Southern California), Julius J. Mondragon III (Tidelands Oil Production), :"Conceptual Model of Fault Block II-A, Wilmington Field, from Field Performance Data", SPE Paper No. 38309, to be presented at the 1997 Western Regional Meeting in Long Beach, CA, 23-27 June.

[A15] Iraj Ershaghi, Pouya Amili (University of Southern California), :"Correlations for Prediction of Steamflood Oil Recovery in Steam-Assisted Gravity Drainage (SAGD) Process Using Horizontal Injectors and Producers", SPE Paper No. 38297, to be presented at the 1997 Western Regional Meeting in Long Beach, CA, 23-27 June.

[A16] Walt Whitaker II (Tidelands Oil Production), :"7-ppm No_x 50 MM BTU/hr Oilfield Steam Generator Operating on Low-Btu Produced Gas", SPE Paper No. 38277, to be presented at the 1997 Western Regional Meeting in Long Beach, CA, 23-27 June.

[A17] F. Scott Walker (Tidelands Oil Production), :"Locating and Producing Bypassed Oil: A DOE Project Update", SPE Paper No. 38283, to be presented at the 1997 Western Regional Meeting in Long Beach, CA, 23-27 June.

[A18] Richard Cassinis (Tidelands Oil Production), William A. Farone (Applied Power Concepts, Inc.),: "Improved H_2S Caustic Scrubber", SPE Paper No. 38273, to be presented at the 1997 Western Regional Meeting in Long Beach, CA, 23-27 June.

[A19] David K. Davies (David K. Davies and Associates), Julius J. Mondragon III, P. Scott Hara (Tidelands Oil Production), :"A Novel Low-Cost Well Completion Technique Using Steam for Formations with Unconsolidated Sands, Wilmington Field, California", SPE Paper No. 38793, to be presented at the 1997 Western Regional Meeting in Long Beach, CA 23-27 June.

[A20] David K. Davies, Richard K. Vessel (David K. Davies and Associates), :"Nature, Origin, Treatment and Control of Well-Bore Scales in an Active Steamflood, Wilmington Field, California", SPE Paper No. 35418, to be presented at the 1996 Society of Petroleum Engineers/Department of Energy Tenth Symposium on Improved Oil Recovery in Tulsa, OK 21-14 April.

[A21] David K. Davies, Richard K. Vessel (David K. Davies and Associates), :"Improved Prediction of Permeability and Reservoir Quality through Integrated Analysis of Pore Geometry and Openhole Logs: Tar Zone, Wilmington Field, California", SPE Paper No. 38262, to be presented at the 1997 Western Regional Meeting in Long Beach, CA, 23-27 June.

A22 David K. Davies, John Aumon, Richard K. Vessel (David K. Davies and Associates), :"Improved Prediction of Reservoir Behavior through Integration of Quantitative Geological and Petrophysical Data", SPE Paper No. 38914, to be presented at the 1997 Society of Petroleum Engineers Annual Technical Conference and Exhibition in San Antonio, TX, 6-8 October.

A23 Iraj Ershaghi, Chang-An Du, Linji An (University of Southern California), :"A Three Stage Conditioning Process for Scrutinizing Stochastic Representation of a Turbidite Sequence in a Densely Drilled Formation", SPE Paper No. 38681, not done in 1997 as planned.

A24 Iraj Ershaghi, M. Hassibi (University of Southern California), :"A Neural Network Approach for Correlation Studies in a Complex Turbidite Sequence", SPE Paper No. 36720.

A25 Zhengming Yang, Linji An (University of Southern California): Developed COMPACT software program to be incorporated as module into Computer Modeling Group's STARS thermal simulator program. COMPACT is an algorithm that can mimic local and dynamic features of rock compaction and rebound as a function of reservoir pressure.

B. Secondary publications

B1 Steve Bell, : "Extraction Technologies May Increase Recoverable Reserves by Billions", Hart's Petroleum Engineer, Tech Trends, page 9, March 1995.

B2 Donald D. Clarke, Xen Colazas (City of Long Beach), Janet Wiscombe (Los Angeles Times), :"Drilling in Disguise", Los Angeles Times, Metro Section, page B2, 15 November 1996.

B3 Chris C. Phillips (Tidelands Oil Production), Pat Prince Rose (Los Angeles Times), :"In Geological Time, He's Ancient", Los Angeles Times, Business Section, Trends, page D5, 9 December 1996.

B4 Iraj Ershaghi (University of Southern California), Frank Clifford (Los Angeles Times), :"A New Oil Boom", Los Angeles Times, Metro Section, Next L.A., page B2, 24 December 1996.

B5 Richard Cassinis, Sean Massey (Tidelands Oil Production), Stuart M. Heisler (TJ Cross Engineers Inc.), for the Sulfatreat Company :"The Story Behind Lo~CoST^{SM}", Oil, Gas and Petrochem Equipment Magazine, back cover page, March 1997. Advertisement by the Sulfatreat Company on product developed through the DOE project work related to "Improved H_2S Caustic Scrubber" technology. Also refer to, http://www.ingersoll-rand.com/compair

B6 Iraj Ershaghi (University of Southern California), Herb Tiderman (DOE), Gail Dutton (Compressed Air Magazine), :"Coaxing Crude From The Ground", Compressed Air Magazine, pages 22-26, March 1997.

B7 Jeff Schwalm (Dynamic Graphics Inc.), Chris C. Phillips (Tidelands Oil Production), :"Earth Vision Software Solutions for Structurally Consistent 3-D Geologic Modeling, 3-D Well Placement Planning", Advertisement Mailer sent to the 1997 American Association of Petroleum Geologists (AAPG) Annual Meeting attendees, conducted 7-9 April 1997. Mailer contains copy of "3-D Modeling, Horizontal Drilling... Gives New Life to Aging Fields"[25]. Wilmington DOE projects featured in Dynamic Graphics' exhibit booth at convention and in internet homepages: (info@dgi.com and http://www.dgi.com/topko.html)

[B8] University of Southern California. West Coast DOE projects comprehensively summarized and can be accessed at: http://www.usc.edu/dept/peteng/doe.html. Summarized content of the previous year's annual report is located at: http://www.usc.edu/dept/peteng/topko.html

[B9] University of Southern California. A collection of interviews and presentations saved as brief movie clips detailing the scope of operations at Tidelands Oil production related to the Class III DOE project on CD-ROM.

C. Presentations, Tours, Other Activities from which no new reference materials were generated.

[C1] Christopher Phillips (Tidelands Oil Production), :"Application of Advanced Reservoir Characterization to Increase the Efficiency of a Thermal Steam Drive in the Wilmington Oil Field", presented at the AAPG Pacific Section Meeting, San Francisco, CA, 4 May 1995.

[C2] Donald D. Clarke (City of Long Beach), chaired the AAPG Pacific Section Meeting, San Francisco, CA, 3-5 May 1995.

[C3] Donald D. Clarke (City of Long Beach), conducted eight field tours of the Wilmington Field for students, geologists, engineers, public officials, civic groups and senior groups, January-June 1996.

[C4] David K. Davies (David K. Davies & Associates), Julius Mondragon and Scott Hara (Tidelands Oil Production), : "Novel Sand Consolidation Completion Technique Using Alkaline Steam Injection in the Tar Zone, Fault Block II-A, Wilmington Field, CA", poster session presented at the 1996 Annual Meeting of the American Association of Petroleum Geologists (AAPG) in San Diego, California, May 1996

[C5] David K. Davies (David K. Davies and Associates), :"Mineralogy and Origin of Well-Bore Scales in an Active Steamflood: Tar Zone, Fault Block II-A, Wilmington Field, California", presentation at the 1996 Annual Meeting of the American Association of Petroleum Geologists (AAPG) in San Diego, California, May 1996.

[C6] David K. Davies (David K. Davies and Associates), :"Flow Unit Modeling in Complex Reservoirs", presentation at the 1996 Annual Meeting of the American Association of Petroleum Geologists (AAPG) in San Diego, California, May 1996.

[C7] Steve Siegwein (Tidelands Oil Production), :"Review of Recent Well Drilling Activities by THUMS Long Beach Company and Tidelands Oil Production Company", Oral Presentation at the Society of Petroleum Engineers Los Angeles Basin Environmental and Study Group Forum, Long Beach Petroleum Club, 25 September 1996.

[C8] Mark Kapelke (Tidelands Oil Production), :"Multimedia and Technical Transfer", Oral Presentation at the PTTC Problem Identification Workshops held in Bakersfield (20 November 1996), Long Beach (25 November 1996), and Ventura (26 November 1996).

[C9] Zhengming Yang (University of Southern California), :"Tar zone reservoir simulation on primary production", Oral presentation at the opening ceremony of the West Coast PTTC Office, facilities tour. West Coast PTTC Office, University of Southern California, Los Angeles, CA, 6 December 1996.

[C10] Yucel I. Akkutlu, Lyman L. Handy (University of Southern California), :"Tar zone reservoir material balance studies", Oral presentation at the opening ceremony of the West Coast PTTC Office, facilities tour. West Coast PTTC Office, University of Southern California, Los Angeles, CA, 6 December 1996.

C11 Linji An (University of Southern California), :"Geologic 3-D Modeling", Oral presentation at the opening ceremony of the West Coast PTTC Office, facilities tour. West Coast PTTC Office, University of Southern California, Los Angeles, CA, 6 December 1996.

C12 Chang-An Du (University of Southern California), :"Stochastic Reservoir Modeling", Oral presentation at the opening ceremony of the West Coast PTTC Office, facilities tour. West Coast PTTC Office, University of Southern California, Los Angeles, CA, 6 December 1996.

C13 Mark Kapelke (Tidelands Oil Production), :"CD-ROM Project", Oral presentation at the opening ceremony of the West Coast PTTC Office, facilities tour. West Coast PTTC Office, University of Southern California, Los Angeles, CA, 6 December 1996.

C14 Donald D. Clarke (City of Long Beach), Chris C. Phillips (Tidelands Oil Production), Linji An (University of Southern California), :"Case Histories - DOE Supported Projects, Thermal Flood, Tar Zone, Wilmington Oil Field", Oral Presentation at the PTTC Workshop on California Geology With and Without Computer Graphics, University of Southern California, Los Angeles, CA, 15 January 1997.

C15 Donald D. Clarke (City of Long Beach), :"New Ways to do Geology", PTTC Workshop on California Geology With and Without Computer Graphics, University of Southern California, Los Angeles, CA, 15 January 1997.

C16 Iraj Ershaghi (University of Southern California), Donald D. Clarke (City of Long Beach): Co-ordinators of the PTTC Focused Technology Workshop entitled "California Geology With or Without Computer Graphics", University of Southern California, Los Angeles, CA, 15 January 1997.

C17 Iraj Ershaghi (University of Southern California), :"Geological Control on Reservoir Productivity", PTTC Workshop on California Geology With and Without Computer Graphics, University of Southern California, Los Angeles, CA, 15 January 1997.

C18 Rick Cassinis, Sean Massey (Tidelands Oil Production), Stuart M. Heisler (TJ Cross Engineers Inc.), :"Improved H_2S Caustic Scrubber", Oral Presentation at the 1997 8th Annual Energy week Conference and Exhibition sponsored by API and ASME in Houston, TX, 30 January.

C19 Mohd. Al-Qahtani, Iraj Ershaghi (University of Southern California), :"Characterization and Estimation of Permeability Correlation Structure from Performance Data", presented at the 4th International Reservoir Characterization Technical Conference sponsored by the DOE, BDM, and the American Association of Petroleum Geologists (AAPG), 2-4 March 1997.

C20 Jeff Schwalm, John Perry (Dynamic Graphics Inc.), :"3-D Geologic Modeling: Theory and Application", ½ day workshop sponsored by the PTTC at USC Campus, Los Angeles, CA on 2 May 1997. Presentation utilizes 3-D Deterministic Geologic Model from this project to explain fundamentals of 3-D Geologic Modeling.

C21 M. Hassibi, Iraj Ershaghi (University of Southern California), :"Characterization of Lithological Log Responses in Turbidite Series using Neural Networks", oral presentation at the 1997 American Association of Petroleum Geologists (AAPG) Pacific Section Convention in Bakersfield, CA, 14-16 May 1997.

[C22] David K. Davies, Richard K. Vessel (David K. Davies and Associates), :"Geological Controls on Permeability Distribution and Sand Distribution: Tar Zone, Fault Block II-A, Wilmington Field", oral presentation at the 1997 American Association of Petroleum Geologists (AAPG) Pacific Section Convention in Bakersfield, CA, 14-16 May.

[C23] Donald D. Clarke (City of Long Beach): Project status presentation for DOE/BDM conference regarding status of all DOE contracted projects, Houston, TX, 16-20 June 1997.

[C24] Julius J. Mondragon III, P. Scott Hara (Tidelands Oil Production), :"Novel Sand Consolidation Completion Technique Using Alkaline-Steam Injection in the Tar Zone, Wilmington Field", SPE GEM Presentation No. WR GEM 29, to be presented at the 1997 Western Regional Meeting in Long Beach, CA 23-27 June.

[C25] Chris C. Phillips, P. Scott Hara (Tidelands Oil Production), :"Three-Dimensional Geological Modeling as a Cost-Effective Tool for Horizontal Drilling", SPE GEM Presentation No. WR GEM 6, to be presented at the 1997 Western Regional Meeting in Long Beach, CA 23-27 June.

[C26] Mark Kapelke (Tidelands Oil Production), "How to Work With the DOE" and "Multimedia and Technical Transfer", National Petroleum Technology Resource Center sponsored by the DOE, to be presented at the 1997 Western Regional Meeting in Long Beach, CA 23-27 June.

D. Outside References Cited

[D1] Small, G.P., Shell California Production Inc. :"Steam-Injection Profile Control Using Limited-Entry Perforations", SPE Paper 13607, presented at the 1985 California Regional Meeting in Bakersfield, CA, March 27-29 1985.

[D2] R.M. Butler, :"Gravity Drainage to Horizontal Wells", Journal of Canadian Petroleum Technology, Volume 31, No. 4, pages 31-37, April 1992.

[D3] F.H. Lim, W.B. Saner and W.H. Stillwell (Union Pacific Resources Co.) and J.T. Patton (New Mexico State University), :"Steamflood Pilot Test in Waterflooded, 2500 ft. Tar Zone Reservoir, Fault Block II Unit, Wilmington Field, California", presented at the 1993 Society of Petroleum Engineers Annual Technical Conference and Exhibition in Houston, TX, 3-6 October 1993.

[D4] R.M. Butler, : "Horizontal Wells for the Recovery of Oil, Gas and Bitumen; Monograph 2" , Petroleum Society of CIM, Calgary 1994.

[D5] M. Polikar, D.A. Redford, : "Evolution of Steam-Based Technology for the Recovery of Canadian Heavy Oil Reservoirs", Journal of Petroleum Technology, Volume 34, No. 5, pages 33-40, May 1995.

E. Reports Generated for the Department of Energy.

[E1] P. Scott Hara (Tidelands Oil Production), "Quarterly Technical Progress Report - Class III Mid-Term Project, "Increasing Heavy Oil Reserves in the Wilmington Oil Field Through Advanced Reservoir Characterization and Thermal Production Technologies", EE-FC22-95BC14939", 1st Quarter (1 April 1996 - 30 June 1996). Submitted to the U.S. Dept. of Energy (DOE).

[E2] P. Scott Hara (Tidelands Oil Production), "Quarterly Technical Progress Report - Class III Mid-Term Project, "Increasing Heavy Oil Reserves in the Wilmington Oil Field Through Advanced Reservoir Characterization and Thermal Production Technologies", EE-FC22-95BC14939", 2nd Quarter (1 July 1996 - 30 September 1996). Submitted to the U.S. Dept. of Energy (DOE).

[E3] P. Scott Hara (Tidelands Oil Production), "Quarterly Technical Progress Report - Class III Mid-Term Project, "Increasing Heavy Oil Reserves in the Wilmington Oil Field Through Advanced Reservoir Characterization and Thermal Production Technologies", EE-FC22-95BC14939", 3rd Quarter (1 October 1996 - 31 December 1996). Submitted to the U.S. Dept. of Energy (DOE).

[E4] P. Scott Hara (Tidelands Oil Production), "Quarterly Technical Progress Report - Class III Mid-Term Project, "Increasing Heavy Oil Reserves in the Wilmington Oil Field Through Advanced Reservoir Characterization and Thermal Production Technologies", EE-FC22-95BC14939", 4th Quarter (1 January 1997 - 31 March 1997). Submitted to the U.S. Dept. of Energy (DOE).

[E5] Project Team, Annual Report entitled :"Increasing Heavy Oil Reserves in the Wilmington Oil Field through Advanced Reservoir Characterization and Thermal Production Technologies", EE-FC22-95BC14939", 1st Reporting Period (30 March 1995 - 31 March 1996). Submitted to the U.S. Dept. of Energy (DOE).